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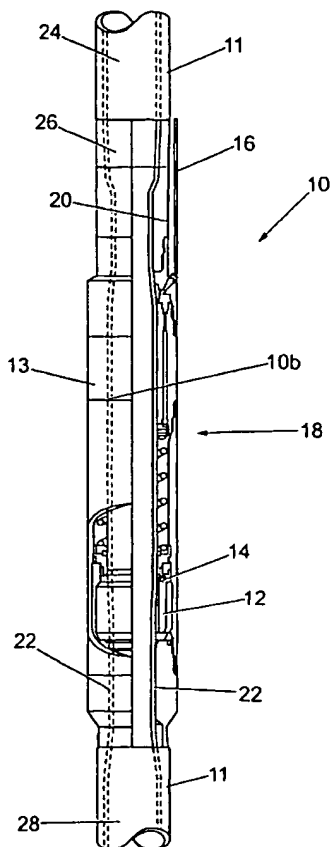
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(54) Title: METHOD AND APPARATUS



(57) Abstract: Aspects of the invention relate to apparatus and methods for remedial and repair operations downhole. Certain embodiments of apparatus include a lightweight expandable member (22) that can be radially expanded to increased its inner and outer diameters using an inflatable element (34). The lightweight member (22) can be used to repair a faulty safety valve flapper (12) for example. The invention also relates to lateral tubular adapter apparatus and a method of hanging a lateral from a cased borehole.

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1 "Method and apparatus"

2

3 Aspects of the present invention relate to a method
4 and apparatus for various remedial or repair
5 operations in oil and gas wells. Certain other
6 aspects of the present invention have applications
7 in the context of lateral boreholes.

8

9 It is known to use expandable tubular members to
10 line or case boreholes that have been drilled into a
11 formation to facilitate the recovery of
12 hydrocarbons. The expandable tubular members are
13 typically of a ductile material so that they can
14 withstand plastic and/or elastic deformation to
15 radially expand their inner diameter (ID) and/or
16 outer diameter (OD). The tubular members can
17 typically sustain a plastic deformation to expand
18 their OD and/or ID by around 10% at least, although
19 radial plastic deformation in the order of 20% or
20 more is possible.

21

1 The radial expansion of the tubular members can
2 typically be achieved in one of two ways.

3
4 A radial expansion force can typically be applied by
5 an inflatable element (e.g. a packer or other such
6 apparatus that is capable of inflating or otherwise
7 expanding) to a particular portion of the member, so
8 that the inflatable element is inflated within the
9 member to radially expand the member at the
10 particular portion thereof. This can be repeated at
11 one or more locations either adjacent to the
12 particular portion, or spaced therefrom.

13
14 Alternatively, an expander device can be pushed or
15 pulled through the member to impart a radial
16 expansion force to the casing so that the ID and/or
17 the OD of the member increases. This is generally
18 called radial plastic deformation in the art, but
19 "radial expansion force" will be used herein to
20 refer to both of these options.

21
22 According to a first aspect of the present
23 invention, there is provided a tubular remedial
24 apparatus for performing downhole remedial or repair
25 operations on downhole tubulars such as casing,
26 liner or the like in a wellbore, the apparatus
27 comprising an expandable tubular member and at least
28 one expander element.

29
30 According to a second aspect of the present
31 invention, there is provided a method of performing
32 downhole repair or remedial operations, the method

1 comprising the steps of providing an expandable
2 member; locating the member in a tubular in the
3 borehole; providing at least one expander element
4 and locating this within the expandable member; and
5 actuating the expander element to radially expand at
6 least a portion of the expandable member against the
7 wellbore tubular.

8
9 The expander element can be integral with the
10 expandable member, or can be separate therefrom.

11
12 The expandable member is typically a lightweight
13 member such as a thin-walled tubular member. The
14 wall thickness of the lightweight member is
15 typically up to around 5 millimetres. The
16 lightweight member is typically of stainless steel
17 or an alloy of steel (e.g. a nickel alloy).
18 Alternatively, the expandable member can be a
19 heavyweight tubular having a wall thickness of
20 greater than 5 mm. For lightweight members, the
21 diameter-to-thickness ratio is in the order of 40 to
22 60, whereas the diameter-to-thickness ratio of a
23 heavyweight expandable tubular member is typically
24 around 20 to 30.

25
26 In preferred embodiments, the expandable member
27 comprises a tubular with a central heavyweight
28 portion disposed between two lightweight portions.
29 Optionally, the central heavyweight portion is
30 provided with at least one orifice. This particular
31 expandable member can be used to repair a faulty gas
32 lift valve, for example.

1
2 The expandable member is typically a one-piece
3 member. The expandable member can be in the form of
4 a coil or a roll for example. Alternatively, the
5 tubular member can comprise two or more portions
6 that are coupled together (e.g. by welding or screw
7 threads).

8
9 Optionally, two axially spaced-apart expander
10 elements can be used. In this embodiment, the
11 elements can be coupled together by a shaft or the
12 like.

13
14 The or each expander element typically comprises an
15 inflatable element, such as a packer or the like.
16 However, a mechanical expander device may also be
17 used.

18
19 In its broadest context, the method of the second
20 aspect of the present invention facilitates the
21 repair of a damaged or faulty casing, liner or the
22 like. In this embodiment, the expandable member is
23 located in the casing, liner or the like at the
24 damaged or faulty area, and radially expanded so
25 that at least a portion of the member contacts an
26 inner surface of the casing, liner or the like.
27 Thus, the expandable member overlays the damaged or
28 faulty casing, liner etc.

29
30 In a particular embodiment of the invention, the
31 method can be used to repair a faulty or damaged
32 valve located in a tubular. In this case, the

1 method comprises the steps of locating the
2 expandable member in a bore of the tubular so that
3 it straddles the valve; locating the expander
4 element in the expandable member at a first portion
5 of the expandable member; actuating the expander
6 element to expand the first portion of the
7 expandable member; de-actuating the expander
8 element; moving the expander element to a second
9 portion of the expandable member; and actuating the
10 expander element to expand the second portion of the
11 expandable member.

12

13 The first and second portions of the expandable
14 member typically comprise first and second ends of
15 the expandable member. However, the member need
16 only be expanded on each side of the valve.

17

18 Optionally, the method may be used to expand the
19 entire length of the expandable member by de-
20 actuating the expander element and moving it to
21 another location between the first and second
22 portions of the member, and then re-actuating it to
23 expand the expandable member at the other location.
24 The expander element may be moved more than once and
25 expanded at more than one other location.

26

27 The valve may comprise a safety valve, chemical
28 injection valve, gas lift valve, sliding sleeve
29 valve or the like.

30

31 According to a third aspect of the present
32 invention, there is provided a lateral tubular

1 adapter apparatus, the apparatus having a
2 longitudinal bore and at least one expander element.

3
4 According to a fourth aspect of the present
5 invention, there is provided a method of hanging a
6 lateral tubular from a cased wellbore, the method
7 comprising the steps of providing a conduit having a
8 longitudinal bore and at least one expander element,
9 the conduit having an aperture therein; locating the
10 conduit at or near a lateral opening in the casing
11 of the borehole; and expanding the or each expander
12 element to radially expand portions of the conduit
13 on opposite sides of the aperture.

14
15 The apparatus preferably has first and second
16 axially spaced-apart expander elements, preferably
17 located on opposite sides of the aperture.

18
19 The opening in the borehole typically comprises a
20 lateral borehole.

21
22 The conduit is typically a lightweight or
23 heavyweight member as discussed above.

24
25 The aperture in the conduit is typically teardrop
26 shaped, but other shapes may also be used, such as
27 ovals, circles, ellipses etc.

28
29 The expander element typically comprises an
30 inflatable element as described above. An annular
31 chamber is typically located under a plurality of
32 overlapping metal plates. The annular chamber is

1 typically in fluid communication with the bore of
2 the apparatus, e.g. via one or more ports. An
3 elastomeric covering is typically located over the
4 metal plates. The metal plates typically overlap in
5 the longitudinal direction (i.e. in a direction that
6 is parallel to the longitudinal axis of the
7 apparatus).

8
9 The step of actuating the inflatable element
10 typically includes the additional step of providing
11 pressurised fluid in the annular chamber. The
12 pressurised fluid typically expands the metal plates
13 and/or the elastomeric covering.

14
15 The inflatable elements typically include one or
16 more ports that are in fluid communication with the
17 annular chamber. The ports typically include a
18 rupture or burst disc therein. The rupture or burst
19 disc is typically rated to burst at around 4000 psi.

20
21 The apparatus typically includes a first centraliser
22 located at or near each inflatable element. The
23 first centraliser comprises two or more radially
24 extending blades or the like that engage an inner
25 surface of the conduit. A portion of the first
26 centraliser typically engages at least a portion of
27 the inflatable element. The first centraliser
28 typically engages at least the elastomeric covering
29 of the inflatable element. The first centraliser
30 includes one or more shear screws that retain the
31 first centraliser in a certain axial location with
32 respect to the inflatable element. The first

1 centraliser thus prevents premature inflation of the
2 inflatable element by preventing the elastomeric
3 covering from radially expanding. The shear screws
4 are typically rated to shear at around 500 psi.

5
6 The step of inflating the inflatable elements
7 typically includes the additional step of applying a
8 pressure in the annular chamber of the inflatable
9 elements, the pressure being greater than the rating
10 of the shear screws to shear the shear screws of the
11 first centraliser. The shearing of the shear screws
12 typically allows the first centraliser to move
13 axially towards the inflatable element, thus
14 allowing the elastomeric covering to expand. Thus,
15 the first centraliser prevents the inflatable
16 element from prematurely inflating until the shear
17 screws shear.

18
19 The apparatus typically includes at least one second
20 centraliser for centralising the conduit on the
21 inflatable elements as the apparatus is run into a
22 borehole. The or each second centraliser typically
23 includes a groove for receiving an O-ring. The O-
24 ring is typically compressed when the inflatable
25 element is expanded. Compression of the O-ring
26 causes the or each centraliser to be retained on the
27 apparatus. Alternatively, the second centraliser
28 comprises a ring of resilient material (e.g. rubber)
29 that engages the conduit, and a retaining clamp. A
30 second centraliser is typically located at a first
31 end of the conduit.

32

1 At least a portion of the conduit is typically
2 swaged. The swaged portion is typically at a second
3 end of the conduit. The swaged portion typically
4 engages a least a portion of the apparatus (e.g. one
5 of the inflatable elements). The swaged portion
6 substantially prevents the ingress of dirt, fluids
7 etc into an annulus between the apparatus and the
8 conduit as the apparatus is being run into the
9 borehole. Alternatively, or additionally, a further
10 centraliser may be located at the second end. The
11 or each second centraliser also prevents the ingress
12 of wellbore debris and the like into an annulus
13 between the or each inflatable element and the
14 conduit.

15

16 The apparatus typically includes a retainer sub that
17 is located between the first and second inflatable
18 elements. The retainer sub includes a piston that
19 is capable of moving along an axis that is
20 substantially parallel to a longitudinal axis of the
21 apparatus. A surface of the piston is adapted to
22 engage at least one radial piston. Preferably, four
23 radial pistons are provided, each radial piston
24 being circumferentially spaced-apart from the others
25 (e.g. by 90°). The or each radial piston is
26 typically set on an axis that is substantially
27 perpendicular to the longitudinal axis of the
28 apparatus. Movement of the piston in a first
29 direction typically moves the piston to a first
30 configuration in which the surface engages the or
31 each radial piston. The engagement of the piston
32 with the or each radial piston typically causes the

1 or each radial piston to be moved radially outward
2 so that an end thereof engages an inner surface of
3 the conduit. Thus, the conduit is retained in place
4 by the engagement of the or each radial piston
5 therewith. Movement of the piston in a second
6 direction, typically opposite to the first
7 direction, typically moves the piston to a second
8 configuration where the surface disengages the or
9 each radial piston. In this configuration, the or
10 each radial piston can disengage the conduit. The
11 piston is typically held in the first configuration
12 by one or more shear screws. The shear screws are
13 typically rated to shear at around 500 psi.

14

15 The method typically includes the additional steps
16 of applying pressure to a first end of the piston to
17 move the piston to the first configuration, and
18 locating the shear screws to retain the piston in
19 the first configuration. The method typically
20 includes the additional steps of applying a pressure
21 to a second end of the piston, the pressure
22 typically being higher than the rating of the shear
23 screws, to move the piston to the second
24 configuration.

25

26 The apparatus typically includes a locator. The
27 locator typically facilitates alignment of the
28 aperture in the conduit with the opening to the
29 lateral borehole. In one embodiment, the locator
30 comprises a spring-loaded arm.

31

1 The method typically includes the additional step of
2 locating the locating arm in an extended portion of
3 the aperture in the conduit. The extended portion
4 typically comprises an elongate slot. The method
5 typically includes the additional step of running
6 the apparatus into the borehole until the locating
7 arm locates the opening to the lateral borehole.

8

9 The apparatus typically includes a ball catcher
10 located at a distal end of the apparatus. The ball
11 catcher typically includes a ball seat that is
12 typically capable of receiving a ball. The ball
13 seat is typically coupled to the ball catcher using
14 one or more shear screws. The shear screws are
15 typically rated to shear at around 3000 psi. The
16 ball seat is movable from a first position where it
17 blocks one or more ports in the apparatus, to a
18 second position where it opens the ports in the
19 apparatus. The ports in the apparatus are typically
20 in fluid communication with the bore of the
21 apparatus.

22

23 The method typically includes the additional step of
24 dropping a ball into the borehole before pressure is
25 applied in the bore of the apparatus.

26

27 The method typically includes the additional step of
28 applying a pressure to the ball that exceeds the
29 rating of the shear screws to move the ball seat to
30 the second position. This allows the pressure in
31 the bore to be vented into the borehole via the
32 ports. The venting of the pressure allows the

1 inflatable elements to deflate and thus the
2 apparatus can be retrieved from the borehole.

3
4 The method optionally includes the additional steps
5 of applying a pressure of around 4000 psi to the
6 bore of the apparatus to rupture the burst discs in
7 the or each inflatable element. This allows the
8 pressure in the bore of the apparatus to be vented
9 outwith the apparatus.

10
11 Embodiments of the present invention shall now be
12 described, by way of example only, with reference to
13 the accompanying drawings, in which:

14 Fig. 1 is a part cross-sectional view of a
15 safety valve that has been repaired using one
16 embodiment of a method according to an aspect
17 of the present invention;

18 Figs 2a to 2c one embodiment of apparatus
19 according to an aspect of the present invention
20 in various stages of expanding a tubular
21 member;

22 Fig. 3 is a part cross-sectional view of a
23 sliding sleeve that has been repaired using one
24 embodiment of a method according to an aspect
25 of the present invention;

26 Fig. 4 is a part cross-sectional elevation of a
27 mandrel valve that houses a gas lift valve that
28 has been repaired using one embodiment of a
29 method according to an aspect of the present
30 invention;

1 Figs 5a to 5d are four cross-sectional
2 elevations of a gas lift orifice showing the
3 stages of repair;
4 Fig. 6a shows a part cross-sectional elevation
5 of a casing and a lateral borehole that has
6 been provided with a portion of one embodiment
7 of apparatus according to an aspect of the
8 present invention;
9 Fig. 6b shows a perspective view of a conduit
10 for use with one embodiment of apparatus
11 according to an aspect of the present
12 invention;
13 Figs 7a to 7i are cross-sectional elevations
14 that together show an embodiment of apparatus
15 according to an aspect of the present
16 invention;
17 Fig. 8 shows an enlarged view of a centraliser
18 forming part of the apparatus of Fig. 7a; and
19 Fig. 9 shows a similar view of the apparatus of
20 Fig. 7a with an alternative centraliser.
21
22 Referring to the drawings, Fig. 1 shows in part
23 cross-section a conventional safety valve, generally
24 designated 10. Safety valve 10 includes a flapper
25 12 that can be moved from an open position (shown in
26 Fig. 1) to a closed position (not shown). The
27 safety valve 10 is typically located as part of a
28 production string 11 through which fluids (e.g.
29 hydrocarbons) are recovered from a payzone or
30 reservoir (not shown) to the surface.
31

1 Safety valve 10 includes a mandrel 13 in which the
2 flapper 12 is located. Mandrel 13 is typically
3 coupled to the production string 11 using any
4 conventional means (e.g. conventional pin and box
5 connections).

6
7 In the open position, flapper 12 lies generally
8 parallel to a longitudinal axis of the safety valve
9 10 and thus does not obstruct the flow of fluids
10 through a bore 10b of the safety valve 10. Thus,
11 fluids can flow through the safety valve 10 and the
12 production string 11 to the surface. In the closed
13 position, the flapper 12 is pivoted upwards (with
14 respect to the orientation of the valve 10 in Fig.
15 1) through 90° around a pivot pin 14 or the like so
16 that the flapper 12 lies substantially perpendicular
17 to the longitudinal axis of the safety valve 10 and
18 thus closes bore 10b thereby preventing the flow of
19 hydrocarbons and the like through the valve 10 and
20 the production string 11.

21
22 Operation of the safety valve 10 is typically
23 achieved via a control line 16 that extends from the
24 valve 10 back to the surface (not shown). The
25 control line 16 is used to actuate a piston and
26 spring mechanism, generally designated 18, that
27 controls the actuation of the flapper 12 as is known
28 in the art.

29
30 It is often the case that the flapper 12 becomes
31 stuck in the closed position and thus prevents
32 fluids from flowing through the production string 11

1 by blocking the bore 10b of the safety valve 10.

2 When this occurs, it is necessary to perform a
3 remedial operation to open the flapper 12 to
4 facilitate the recovery of hydrocarbons.

5

6 When the flapper 12 becomes stuck in the closed
7 position, an insert valve (not shown) can be landed
8 on an upper profile 20 (nipple) and the flapper 12
9 can be controlled using a punch (not shown). The
10 punch provides a jarring action that can be used to
11 punch through into the control line and operate the
12 flapper 12. However, the insert valve can generally
13 only be used when there is mechanical failure of the
14 safety valve 10.

15

16 Fig. 2 shows a portion of apparatus, generally
17 designated 30, which can be used to isolate the
18 flapper 12 and lock the flapper 12 in the open
19 position. Apparatus 30 includes a portion of
20 lightweight expandable tubular member 32 (e.g.
21 casing, liner, drill pipe or the like). The
22 lightweight expandable member 32 is generally a
23 thin-walled tubular of up to around 5mm wall
24 thickness that is typically of stainless steel or an
25 alloy of steel (e.g. a nickel alloy). The force
26 required to radially expand a thin-walled (or
27 lightweight) tubular is typically less than that
28 required to expand a conventional expandable tubular
29 member that typically has a wall thickness of
30 greater than 5mm. For lightweight pipe, the
31 diameter-to-thickness ratio is in the order of 40 to
32 60, whereas the diameter-to-thickness ratio of

1 conventional expandable tubular members is around 20
2 to 30.

3
4 It will be appreciated that conventional expandable
5 members could also be used in the present invention,
6 but lightweight pipe will be referred to as it is
7 preferred for certain embodiments, because less rig
8 equipment need be used for the use of lightweight
9 pipe, and the lightweight pipe itself is easier to
10 handle and requires less force to radially expand
11 it. Also, lightweight pipe facilitates bigger
12 expansion ratios so that the pipe can be inserted
13 into the borehole through other conduits that have
14 relatively small IDs and then radially expanded to
15 increase the ID and/or OD of the lightweight pipe.

16
17 Referring in particular to Fig. 2a, an inflatable
18 element 34 can be used to radially expand the
19 lightweight expandable tubular member 32. The
20 inflatable element 34 may be a packer or the like,
21 but can be of any design that is capable of
22 inflating and deflating. The inflatable element 34
23 is attached to, for example, a coiled tubing string,
24 drill pipe (e.g. a drill string) or a wireline (with
25 downhole pump) or the like so that it can be lowered
26 into the borehole.

27
28 The inflatable element 34 is lowered into the
29 borehole through the bore of the lightweight
30 expandable member 32 and then inflated at the
31 required position to radially expand the ID and/or
32 OD of the member 32, as shown in Fig. 2b. The

1 inflatable element 34 can then be deflated and moved
2 upwards again to a further portion of the member 32
3 that is to be expanded, where it can be re-inflated
4 to increase the ID and/or the OD of the member 32
5 (see the sequence of Figs 2a, 2b and 2c). This
6 process can then be repeated until either the entire
7 length of the member 32 is radially expanded, or
8 until certain portion(s) thereof have been expanded,
9 as will be described.

10

11 It will be appreciated that the member 32 and the
12 inflatable element 34 can be used to repair a faulty
13 or damaged portion of casing, liner or the like in a
14 borehole. The member 32 can be run into the
15 borehole so that it is located within the damaged or
16 faulty portion of the pre-installed casing, liner or
17 the like. Thereafter, the inflatable element 34 is
18 located within the member 32 at a first location
19 (typically one end of the member) and then inflated
20 to expand the member at this first location. The
21 inflatable element 34 is then deflated and moved to
22 a second location, spaced-apart from the first
23 location, and then re-inflated to expand the member
24 32 at the second location. The second location may
25 be at the opposite end of the member 32. This
26 process can be repeated until the entire length of
27 the member 32 is radially expanded into contact with
28 the damaged or faulty casing, liner or the like if
29 required. Thus, the member 32 overlays the damaged
30 or faulty portion of the pre-installed casing, liner
31 or the like.

32

1 Referring again to Fig. 1, there is shown a portion
2 of lightweight expandable tubular member 22 that has
3 been inserted through the bore 10b of the safety
4 valve 10. Note that the member 22 has been shown in
5 Fig. 1 as having portions thereof that have been
6 radially expanded. It will be appreciated that the
7 OD of the member 22 is less than the diameter of the
8 bore 10b and the diameter of the throughbore (not
9 shown) of the production string 11 so that it can be
10 passed from the surface through the string 11 and
11 into the bore 10b of the valve 10.

12

13 As the unexpanded expandable member 22 is passed
14 through the bore 10b, it engages the flapper 12 and
15 pushes it back to the open position as shown in Fig.
16 1. Once the unexpanded expandable member 22 has
17 been located in the correct position, the inflatable
18 element 34 (Fig. 2) is lowered on a wireline or the
19 like into the member 22 so that the inflatable
20 element 34 is located within the bore of the member
21 22. The inflatable element 34 is typically
22 positioned at or near an upper end of the member 22
23 and then inflated to radially expand the member 22
24 at the upper end. It will be noted that "upper" and
25 "lower" are being used with respect to the
26 orientation of the safety valve 10 in Fig. 1, but
27 this is arbitrary.

28

29 The radial expansion of the member 22 causes an
30 outer surface thereof to engage an inner surface of
31 the production string 11 to provide a first expanded
32 portion 24. The inflatable element 34 is then

1 deflated and can be moved downwardly to a second
2 location that is below but adjacent to the first
3 expanded portion 24. The inflatable element 34 is
4 then re-inflated to provide a second expanded
5 portion 26 in the same manner as the first expanded
6 portion 24. It will be appreciated that the first
7 and second expanded portions 24, 26 may be expanded
8 at the same time, depending upon the length of the
9 inflatable element 34 in a direction that is
10 parallel to the longitudinal axis of the safety
11 valve 10. Indeed, the length of the member 22 that
12 is radially expanded by the inflatable element 34 is
13 generally dependent upon the length of the element
14 34.

15
16 It will also be appreciated that only the first
17 expanded portion 34 may be required to keep the
18 member 22 in position. Thus, the inflatable element
19 34 may need to be inflated only once at the upper
20 end.

21
22 Once the upper portions 24, 26 have been expanded,
23 the inflatable element 34 is then lowered through
24 the member 22 to a third location, typically at a
25 lower end of the member 22. At the third location,
26 the inflatable element 34 is then re-inflated to
27 expand the member 22 to provide a third expanded
28 portion 28. Again, the inflatable element 34 can be
29 deflated, moved to a different location, and re-
30 inflated to produce various expanded portions where
31 the member 22 has been radially expanded. Indeed,
32 the inflatable element 34 can be used to radially

1 expand the entire length of the member 22 so that an
2 outer surface thereof engages either an inner
3 surface of the production string 11 or the bore 10b
4 of the safety valve 12, but this is not necessary.

5

6 It will be appreciated that the member 22 need not
7 be expanded at the upper and lower ends thereof, as
8 the member 22 need only be expanded on each side of
9 the flapper 12.

10

11 Thus, the flapper 12 is held in the open position by
12 the overlay of the lightweight expandable tubular
13 member 22 that pushes the flapper 12 back and keeps
14 it in the open position. Heavyweight pipe may also
15 be used where the inflatable element 34 is capable
16 of exerting sufficient force to expand heavyweight
17 pipe.

18

19 It will also be appreciated that the member 22 can
20 be radially expanded at each end simultaneously by
21 using two axially spaced-apart inflatable elements
22 34 that are coupled, for example, by a shaft (not
23 shown in Fig. 1). The length of the shaft will be
24 dependent upon the length of the expandable member
25 22 that is to be located in the bore 10b of the
26 safety valve 10.

27

28 It will further be appreciated that locking the
29 flapper 12 of the safety valve 10 in the open
30 position allows hydrocarbons to be recovered, but it
31 will generally be necessary to install another
32 safety valve elsewhere in the production string 11.

1
2 Referring now to Fig. 3, there is shown a sliding
3 sleeve valve 50 that is typically used to establish
4 communication between a tubing string 52 and an
5 annulus (not shown) between the tubing string 52 and
6 a casing or liner (not shown). Sliding sleeve valve
7 50 includes a mandrel 54 that is provided with
8 attachment means (e.g. conventional pin and box
9 screw thread connectors) so that the valve 50 can be
10 incorporated as part of the tubing string 52.

11
12 Mandrel 54 includes a perforated portion 56 that
13 includes a plurality of circumferentially spaced-
14 apart ports 58. A sleeve 60 is located within
15 mandrel 54 that can slide substantially parallel to
16 a longitudinal axis of the sliding sleeve valve 50.
17 Sleeve 60 is provided with one or more ports 62 that
18 are similar to the ports 58 in the mandrel 60.

19
20 The operation of the sliding sleeve valve 50 is well
21 known in the art, and typically uses a wireline
22 shifting tool that has dogs that engage an upper
23 profile 64 so that the sleeve 60 can be pulled
24 upwards to align the ports 62 with the ports 58.
25 The wireline shifting tool is typically turned
26 upside down so that the dogs engage a lower profile
27 66 to move the sleeve 60 downwards so that the ports
28 62 are no longer aligned with ports 58.

29
30 The sleeve 60 can sometimes become stuck in the open
31 position (i.e. where the ports 58, 62 are aligned).
32 Also, when the ports 62 are mis-aligned with the

1 ports 58 (i.e. when the sleeve 60 is moved
2 downwards) there can sometimes be leakage of
3 production fluids that can be lost into the annulus.
4

5 A lightweight expandable member 68 can be used to
6 isolate the sliding sleeve valve 50 by blocking the
7 ports 58 in the mandrel 54. The expandable member
8 68 is inserted through a bore 54b in mandrel 54 and
9 through bore 52b of the tubing string 52, as shown
10 in Fig. 3. Thereafter, the inflatable element 34 is
11 used to radially expand at least upper and lower
12 portions 68u, 68l of the member 68 as described
13 above. It will be noted that the member 68 has been
14 radially expanded over much of its length in Fig. 3,
15 although this is not necessary. The radial
16 expansion of the upper and lower portions 68u, 68l
17 provides a metal-to-metal seal with the mandrel 54
18 and/or the tubing string 52 and thus fluid flows
19 through the member 68 to the surface.
20

21 Thus, the member 68 prevents any fluid being lost
22 through ports 58, 62 to the annulus, and blocks the
23 ports 58.
24

25 It will again be appreciated that a heavyweight
26 expandable tubular member could be used in place of
27 the lightweight one, providing the inflatable
28 element 34 is capable of exerting sufficient force
29 to expand the heavyweight member.
30

31 It will also be appreciated that the upper and lower
32 ends 68u, 68l of the member 68 could be expanded

1 simultaneously using two axially spaced-apart
2 inflatable elements 34 that are coupled together.
3 The member 68 need not be expanded along its entire
4 length and can merely be expanded at or near the
5 upper and lower ends 68u, 68l (or any other
6 convenient location) to close off and seal the
7 sliding sleeve valve 50.

8
9 Referring now to Fig. 4, there is shown a side
10 pocket mandrel 70 that is a tubing-mounted accessory
11 having a side pocket 72 that can receive a number of
12 different valve assemblies. The side pocket 72 is
13 typically located on the outer diameter of the
14 mandrel 70. The mandrel 70 is provided with
15 attachment means 74, 76 at the ends thereof so that
16 the mandrel 70 can be included as part of e.g. a
17 production string (not shown). The attachment means
18 74, 76 typically comprise conventional pin and box
19 connectors.

20
21 The valve assembly that can be installed in the side
22 pocket 72 may be of any conventional type, such as a
23 chemical injection valve (not shown) or a gas lift
24 valve (not shown) for example. The valve assembly
25 is typically installed in and removed from the side
26 pocket 72 using a wireline (not shown).

27
28 In the event that the valve assembly in side pocket
29 72 fails to operate correctly, a portion of
30 lightweight (or heavyweight) expandable member 78
31 can be used to straddle an opening 80 that allows
32 the valve assembly to communicate with a bore 70b of

1 the mandrel 70. The valve assembly is typically
2 removed first before the expandable member 78 is
3 located in place, although this is not always
4 necessary.

5
6 The inflatable element 34 can then be used to
7 radially expand an upper portion 78u and a lower
8 portion 78l of the member 78 as described above,
9 optionally simultaneously. The member 78 thus
10 straddles the opening 80 and prevents any fluids
11 flowing through the mandrel 70 from being lost. The
12 inflatable element 34 can be used to expand any
13 selected portions of the member 78, or indeed expand
14 it over its entire length.

15
16 Where a gas lift valve assembly is used, the member
17 78 may contain a fixed diameter orifice that will
18 allow gas to be injected from the annulus. Gas lift
19 is a form of enhanced recovery where gas is injected
20 at pressure down the annulus. The side pocket 72 of
21 the mandrel 70 would contain a gas lift valve that
22 is set to open at a certain pressure (typically in
23 the range of between 2000 and 3000 psi). When the
24 pressure in the annulus reaches the pressure that
25 the gas lift valve is set to open at, the valve
26 opens (typically against a spring bias) and allows
27 gas to enter the mandrel 70 and thus the tubing or
28 production string. The gas mixes with the recovered
29 hydrocarbons in the string, thus reducing its
30 density and causing the hydrocarbons to rise to the
31 surface. The injected gas is separated from the
32 hydrocarbons at the surface and re-injected to

1 continue the process. Alternatively, or
2 additionally, the injected gas forms bubbles in the
3 fluids that rise to the surface, sweeping the fluids
4 with them.

5
6 It may not be desirable to completely seal off the
7 gas lift valve using a portion of lightweight or
8 heavyweight expandable member as shown in Fig. 4.
9 Referring to Fig. 5, there is shown a schematic
10 representation of the gas lift valve. The valve is
11 represented by a portion of tubing 82 that is
12 provided with a perforation 84. The perforation 84
13 represents the gas lift valve that allows gas from
14 the annulus to be injected into the tubing 82.

15
16 An expandable tubular member 86 that includes a
17 central heavyweight portion 88 and two lightweight
18 end portions 90, 92 is used to isolate the
19 perforation 84 (i.e. the faulty gas lift valve), but
20 can still provide a path for injected gas. The path
21 is provided by a hardened orifice 94 in the
22 heavyweight portion 88.

23
24 The two end portions 90, 92 may be provided with a
25 coating of a friction and/or sealing material 96 to
26 provide a good anchor and/or seal between the
27 expandable tubular member 86 and the tubing 82. It
28 will be appreciated that members 22, 32, 68 and 78
29 of the previous embodiments may similarly be
30 provided with a friction and/or sealing material 96.
31

1 The friction and/or sealing material 96 is typically
2 a rubber material and may comprise first and second
3 bands that are axially spaced-apart along a
4 longitudinal axis of the member 86. The first and
5 second bands are typically axially spaced by some
6 distance, for example 3 inches (approximately 76mm).

7
8 The first and second bands are typically annular
9 bands that extend circumferentially around an outer
10 surface 86s of the member 86, although this
11 configuration is not essential. The first and
12 second bands typically comprise 1-inch wide
13 (approximately 26mm) bands of a first resilient
14 material (e.g. a first type of rubber). The
15 material 96 need not extend around the full
16 circumference of the surface 86s.

17
18 Located between the first and second bands is a
19 third band (not shown) of a second resilient
20 material (e.g. a second type of rubber). The third
21 band preferably extends between the first and second
22 bands and is thus typically 3 inches (approximately
23 76mm) wide.

24
25 The first and second bands are typically of the same
26 depth as the third band, although the first and
27 second bands may be of a slightly larger depth.

28
29 The first type of rubber (i.e. first and second
30 bands) is preferably of a harder consistency than
31 the second type of rubber (i.e. third band). The
32 first type of rubber is typically 90 durometer

1 rubber, whereas the second type of rubber is
2 typically 60 durometer rubber. Durometer is a
3 conventional hardness scale for rubber.

4
5 The particular properties of the rubber or other
6 resilient material may be of any suitable type and
7 the hardnesses quoted are exemplary only. It should
8 also be noted that the relative dimensions and
9 spacing of the first, second and third bands are
10 exemplary only and may be of any suitable dimensions
11 and spacing.

12
13 An outer face of the bands can be profiled (e.g.
14 ribbed) to enhance the grip of the bands on the
15 tubing 82. The ribs also provide a space into which
16 the rubber of the bands can extend or deform into
17 when the member 86 is expanded, as rubber is
18 generally incompressible.

19
20 The two outer bands being of a harder rubber provide
21 a relatively high temperature seal and a back-up
22 seal to the relatively softer rubber of the third
23 band. The third band typically provides a lower
24 temperature seal.

25
26 The two outer bands of rubber can be provided with a
27 number of circumferentially spaced-apart notches
28 (not shown) e.g. four equidistantly spaced notches
29 can be provided. The notches generally do not
30 extend through the entire depth of the rubber bands
31 and are typically used because the first and second
32 bands are of a relatively hard rubber material and

1 this may stress, crack or break when the member 86
2 is radially expanded. The notches provide a portion
3 of the bands that is of lesser thickness than the
4 rest of the bands and this portion can stretch when
5 the member 86 is expanded. The stretching of this
6 portion substantially prevents the bands from
7 cracking or breaking when the member 86 is expanded.
8 The notches can also provide a space for the rubber
9 to deform or extend into as it is compressed.

10

11 Alternatively, the material 96 may be in the form of
12 a zigzag. In this embodiment, the material 96
13 comprises a single (preferably annular) band of
14 resilient material (e.g. rubber) that is, for
15 example, of 90 durometers hardness and is about 2.5
16 inches (approximately 28mm) wide by around 0.12
17 inches (approximately 3mm) deep.

18

19 To provide a zigzag pattern and hence increase the
20 strength of the grip and/or seal that the material
21 96 provides in use, a number of slots (e.g. 20 in
22 number) are milled into the band of rubber. The
23 slots are typically in the order of 0.2 inches
24 (approximately 5mm) wide by around 2 inches
25 (approximately 50mm) long.

26

27 The slots are milled at around 20 circumferentially
28 spaced-apart locations, with around 18° between each
29 along one edge of the material 96. The process is
30 then repeated by milling another 20 slots on the
31 other side of the material 96, the slots on the
32 other side being circumferentially offset by 9° from

1 the slots on the first side. The slots also provide
2 a space for the rubber to deform or extend into when
3 the member 86 is expanded.
4
5 Figs 5a and 5b show the expandable tubular member 86
6 located in the tubing 82 before it has been
7 expanded. The inflatable element 34 is used to
8 apply a radial expansion force to the lightweight
9 portions 90, 92 only to expand them into contact
10 with an inner surface of the tubing 82, as shown in
11 Figs 5c and 5d. The inflatable element 34 is
12 located on a coiled tubing string, drill string,
13 wireline (with downhole pump) or the like and passed
14 through a bore 82b of the tubing 82 and a bore 86b
15 of the member 86 to the required position.
16 Thereafter, the inflatable element 34 is inflated to
17 radially expand the portions 90, 92. It will be
18 appreciated that the inflatable element 34 may have
19 to be deflated, moved and then re-inflated to expand
20 the length of the lightweight portions 90, 92. This
21 is of course dependent upon the length of the
22 portions 90, 92 and the length of the inflatable
23 element 34.
24
25 The portions 90, 92 can also be expanded
26 simultaneously by providing two inflatable elements
27 34 that are axially spaced-apart as described above.
28
29 As can be seen from Figs 5c and 5d, the friction
30 and/or sealing material 96 comes into contact with
31 the tubing 82 when the portions 90, 92 have been
32 radially expanded. The material 96 generally

1 enhances the grip that the member 86 has on the
2 tubing 82 and can also be used as a seal.

3
4 The heavyweight portion 88 of member 86 is not
5 expanded so that there is an annulus 98 between the
6 heavyweight portion 88 and the tubing 82. Gas from
7 the orifice 84 (i.e. the gas that has been injected
8 through the gas lift valve) flows into the annulus
9 98 and through the hardened orifice 94 in the
10 heavyweight portion 88. The orifice 94 thus allows
11 gas to be injected to enhance the recovery of
12 hydrocarbons.

13
14 It will be appreciated that the gas injection cannot
15 be controlled as well as with a gas lift valve, but
16 the orifice 94 allows gas to be mixed with the
17 hydrocarbons to facilitate their recovery.

18
19 It will also be appreciated that a similar member 86
20 can be used to isolate a faulty or inoperative
21 chemical injection valve or the like.

22
23 Referring to Fig. 6a, there is shown a portion of
24 pre-installed casing 100 that has a lateral borehole
25 102 drilled through a side thereof in a known
26 manner. Casing 100 is typically a 9 and five
27 eighths inch casing (approximately 245mm), and the
28 lateral borehole 102 is typically 8½ inches
29 (approximately 216mm) in diameter.

30
31 When drilling the lateral borehole 102, a milled
32 casing exit or opening 104 is formed at or near the

1 casing 100. The opening 104 is typically drilled or
2 milled at an angle to the longitudinal axis of the
3 casing 100, and the opening 104 that is formed is
4 typically a rough hole in the surrounding formation
5 and the casing 100.

6
7 Conventionally, a hook hanger (not shown) is landed
8 at or near the opening 104 that has a flange (not
9 shown) that mates with the opening 104. However,
10 the flange is generally not a good fit with the
11 opening 104 as the opening 104 is generally not a
12 precise opening in the casing 100 and formation, and
13 is not usually of precise and constant dimensions
14 and shape. When the flange is presented to the
15 opening 104, sand etc can get around the side of the
16 flange that falls into the main bore 100b through
17 casing 100 and can block the main bore 100b thus
18 restricting or preventing the flow of hydrocarbons
19 to the surface. The sand can also cause the blockage
20 of lower lateral boreholes.

21
22 The sand also causes other difficulties, such as
23 blocking the inlets to downhole pumps and the like,
24 and if the sand enters downhole apparatus such as
25 pumps, it can cause components within the apparatus
26 to wear out or otherwise fail. Furthermore, the
27 contamination of the recovered hydrocarbons with
28 sand and the like necessitates sand management at
29 the surface to sift out or otherwise remove the sand
30 from the recovered hydrocarbons, and can also
31 necessitate sand clean-out trips.

32

1 In order to prevent the sand etc from sifting into
2 the bore 100b, a conduit 106 (best shown in Fig. 6b)
3 is located between the flange on the hook hanger and
4 the rough opening 104. Conduit 106 comprises a
5 portion of, for example, lightweight expandable
6 member that has an elongate or tear-shaped aperture
7 108. In use, and as shown in Fig. 6a, aperture 108
8 in conduit 106 is aligned (approximately) with
9 opening 104. Thereafter, end portions 106a, 106b of
10 conduit 106 are radially expanded to provide a
11 coupling between the conduit 106 and the casing 100.
12 An outer surface 106s of the conduit 106 can be
13 provided with a friction and/or sealing material
14 110, similar to material 96 described above, to
15 enhance the grip of the conduit 106 on the casing
16 100 and to provide a seal that prevents the ingress
17 of sand etc into the main bore 100b.

18
19 It will be appreciated that the material 110 may not
20 be required as the radial expansion of the ends
21 106a, 106b of the conduit 106 will provide a metal-
22 to-metal seal by contact of the outer surface 106s
23 with the bore 100b.

24
25 Referring now to Figs 7a to 7i, there is shown in
26 part cross-section an apparatus 150 that is
27 particularly suitable for expanding end portions
28 106a, 106b of the conduit 106. For clarity, the
29 left-hand side of Fig. 6b is a continuation of the
30 right hand side of Fig. 6a and so on. Conduit 106
31 can be either a heavyweight or a lightweight member,
32 but is preferably a lightweight member. The

1 aperture 108 in conduit 106 can be seen in Figs 7c
2 to 7g. Aperture 108 is shaped and sized to conform
3 generally to the opening 104 in the casing 100.

4

5 Referring to Fig. 7a, apparatus 150 includes a
6 connector sub 152 that is provided with a
7 conventional box connection 154 to allow the
8 apparatus 150 to be coupled to a drill string,
9 coiled tubing string, wireline or the like.

10

11 An inflatable element that typically comprises a
12 packer 156 is threadedly coupled to the connector
13 sub 152 at threads 158. Packer 156 includes an
14 annular chamber 160 that is located below a
15 plurality of overlapping metal plates 162. The
16 metal plates 162 typically overlap in the
17 longitudinal direction (i.e. in a direction that is
18 parallel to a longitudinal axis x of the apparatus
19 150). The annular chamber 160 is in fluid
20 communication with a longitudinal bore 164 of the
21 apparatus 150 via a port 166. An elastomeric
22 covering 168 is located over the metal plates 162.

23

24 A centraliser 170, best shown in Fig. 8, is located
25 over the elastomeric covering and engages an end
26 portion 106e of the conduit 106. The centraliser
27 170 is typically of TEFLON™, although it may also be
28 of rubber or any other suitable material. An O-ring
29 172 is located in a groove 174 on the centraliser
30 170 and thus retains the conduit 106 in contact with
31 the apparatus 150, and also retains the centraliser
32 170 in position on the apparatus 150 and the conduit

1 106. In particular, the centraliser 170 keeps the
2 conduit 106 centralised as the apparatus 150 and
3 conduit 106 are run into the hole, and also provides
4 a coupling between the apparatus 150 and conduit
5 106. The centraliser 170 also serves to prevent the
6 ingress of contaminants (e.g. dirt etc) from
7 entering an annulus 176 between the elastomeric
8 covering 168 and the conduit 106. This is
9 particularly the case when the apparatus 150 is
10 being withdrawn from the casing 100 before the
11 apparatus 150 is operated to expand the end portions
12 106a, 106b of the conduit 106.

13

14 Fig. 9 shows a view of the apparatus 150 of Fig. 7a,
15 but the apparatus 150 is provided with an
16 alternative centraliser 180. The centraliser 180
17 comprises a rubber ring 182 that is typically of 90
18 durometers hardness, although other hardnessess may
19 be used. A first end 184 of the rubber ring 182 is
20 located in the annulus 176 between the elastomeric
21 covering 168 and the conduit 106. A metal or other
22 clamp 188 is used to hold the rubber ring 182 in
23 place.

24

25 Referring again to Fig. 7b, a second centraliser 190
26 is threadedly engaged with the packer 156 using
27 threads 192. The second centraliser 190 is used to
28 ensure that the conduit 106 remains central on the
29 apparatus 150 as it is run into the casing 100. The
30 second centraliser 190 is provided with shear screws
31 194 (two shown in Fig. 7b) that are set to shear at
32 a particular pressure (e.g. 500 psi). A port 196

1 that communicates with the bore 164 of the apparatus
2 150 is provided in the second centraliser 190, and a
3 burst disc 198 is located in the port 196. The
4 burst disc 198 is set to rupture at a pressure of
5 around 4000 psi, and is used for the release of
6 pressure in an emergency as will be described.

7
8 The shear screws 194 that are set to shear at around
9 500 psi, also ensure that the packer 156 does not
10 prematurely inflate. This is because the second
11 centraliser 190 cannot move as it is retained in
12 position by the shear screws 194, and thus the
13 elastomeric covering 168 cannot be axially
14 displaced, thereby preventing the packer 156 from
15 inflating.

16
17 Referring now to Figs 7b and 7c, there is shown a
18 retainer sub 200 that is threadedly engaged with the
19 packer 156 at threads 202. The retainer sub 200
20 includes an annular piston 204 that can slide along
21 an axis that is substantially parallel to the
22 longitudinal axis x of the apparatus 150. The
23 retainer sub 200 is provided with a port 206 that
24 communicates fluid from outwith the apparatus 150 to
25 a chamber 208. The fluid enters the chamber 208
26 forcing the piston 202 to the position shown in Fig.
27 7c. As the piston moves to the left in Fig. 7c
28 under fluid pressure, an outer surface 202s of the
29 piston 202 engages a number of radial pistons 210.
30 Fig. 7c shows only two radial pistons 210, but it
31 will be appreciated that four such pistons 210 are

1 typically provided, each being circumferentially
2 spaced-apart by 90°.

3
4 The radial pistons 210 are pushed outwardly by the
5 outer surface 202s as the piston 202 moves to the
6 left. An outer end 210e of the radial pistons 210
7 dimple an inner surface 106i of the conduit 106 and
8 thus provide a means of locking or retaining the
9 conduit 106 in place on the apparatus 150. Indeed,
10 the retainer sub 200 also serves to centralise the
11 conduit 106. It will be appreciated that the radial
12 pistons 210 have been shown as protruding through
13 the conduit 106, but the pistons 210 only require to
14 dimple the inner surface 106i to retain the conduit
15 106 in place. The retainer sub 200 is typically
16 actuated at the surface before the apparatus 150 is
17 run in.

18
19 Figs 7c to 7f show an intermediate sub 220 that is
20 threadedly engaged at a first end with the retainer
21 sub 200 at threads 224, and threadedly engaged at a
22 second end with a locator sub 230, best shown in
23 Fig. 7g, at threads 226.

24
25 Fig. 7g shows a locator sub 230 that includes a
26 spring-loaded locator arm 232. Arm 232 is normally
27 biased to a radially extended position (as shown in
28 Fig. 7g), but can be retracted into a slot 233 in
29 the sub 230. The arm 232 is located in an elongate
30 slot 109 of the aperture 108 in conduit 106 (Fig.
31 6b).

32

1 As the apparatus 150 is being run into the casing
2 100, the arm 232 is pushed back against the spring
3 bias that tends to extend the arm 232. When the
4 apparatus 150 approaches the opening 104 in casing
5 100, the spring loaded arm 232 springs outward
6 through the opening 104 and locates the apparatus
7 150 at a lower end of the opening 104. The locator
8 sub 230 thus ensures that the conduit 106 is located
9 correctly before the ends 106a, 106b are radially
10 expanded, as will be described.

11

12 The locator sub 230 is threadedly engaged at a
13 second end thereof with a second intermediate sub
14 240 at threads 242. Referring to Fig. 7h, the other
15 end of the intermediate sub 240 is threadedly
16 engaged with a second packer 256, which is
17 substantially the same as the first packer 156, at
18 threads 244. Like features of the packer 256 have
19 been designated with the same reference numerals
20 prefixed "2" instead of "1".

21

22 The second packer 256 is threadedly engaged at its
23 second end with a third centraliser 290, which is
24 substantially the same as the second centraliser
25 190, at threads 292. Like parts of the third
26 centraliser 290 have been referenced with the same
27 numeral prefixed "2" instead of "1".

28

29 The end 106b of the conduit 106 is swaged (Fig. 7i)
30 to reduce the diameter thereof so that it engages an
31 outer surface 268s of the elastomeric coating 268.
32 This substantially prevents the ingress of fluid,

1 dirt etc into the annulus 276 between the
2 elastomeric covering 268 and the conduit 106 as the
3 apparatus 150 is run into the casing 100. The first
4 centraliser 170 (Fig. 7a) or the alternative
5 centraliser 180 (Fig. 9) may used in place of, or in
6 addition to, the swaged end 106b. Thus, a
7 centraliser 170, 180 could be used at both ends
8 106a, 106b of the conduit 106.

9
10 The second packer 256 is threadedly engaged at
11 threads 302 with a ball catcher 300 (Fig. 7i). Ball
12 catcher 300 is provided with a ball seat 304 that
13 receives a ball 306 in use. The ball seat 304 is
14 provided with shear screws 308 that retain the seat
15 304 in contact with the ball catcher 300 until a
16 pressure of around 3000 psi is applied to the ball
17 seat 304. The catcher 300 has an annular shoulder
18 310 that retains the ball seat 304 when the shear
19 screws 308 shear, as shown in phantom in Fig. 7i.
20 The ball catcher 300 is also provided with
21 circumferentially spaced-apart ports 312 that are
22 used to bleed off pressure within the apparatus 150
23 as will be described. Four such ports 312 are
24 typically provided, each port 312 being
25 circumferentially spaced-apart from one another by
26 around 90°.

27
28 Operation and use of the apparatus 150 shall now be
29 described, with reference in particular to Figs 6a
30 and 7a to 7i.
31

1 The apparatus 150 is assembled as described above
2 and the conduit 106 is located over the apparatus
3 150 as shown in Figs 7a to 7i. In particular, the
4 spring-loaded arm 232 is located in the elongated
5 slot 109 of the aperture 108 in the conduit 106.
6 The conduit 106 is held in place on apparatus 150
7 initially by the centraliser 170 (Figs 7a and 8) or
8 the centraliser 180 (Fig. 9). Also, the swaged end
9 106b of the conduit 106 (Fig. 7i) engages the outer
10 surface 268s of the elastomeric covering 268 of the
11 second packer 256 that aids to keep the conduit 106
12 in place.
13
14 The conduit 106 is also held in place on the
15 apparatus 150 by actuation of the retainer sub 200.
16 A pressure source (e.g. a hydraulic hand pump or the
17 like) is coupled to the port 206 and pressure is
18 applied to the piston 202 to move it to the position
19 shown in Fig. 7c. As the piston moves from right to
20 left as shown in Fig. 7c, the piston 202 contacts
21 the lower surface of the radial pistons 210 and
22 pushes them radially outward so that the end 210e
23 contacts and dimples the inner surface 106i of the
24 conduit 106. The piston 202 is held in this
25 position by locating a number of shear screws 209
26 (two shown in Fig. 7c) that lock the piston 202 in
27 place. The shear screws 209 are typically rated to
28 shear at a pressure of around 500 psi. Thus, the
29 conduit 106 is rigidly attached to the apparatus 150
30 and also centralised with respect to the apparatus
31 150.
32

1 The apparatus 150 is then attached to a drill
2 string, coiled tubing string or the like using the
3 box connection 154. The apparatus 150 can then be
4 run into the casing 100 on the drill string or
5 coiled tubing string. As the apparatus 150 is being
6 run in, the spring loaded arm 232 is compressed into
7 slot 233 by engagement with the casing 100.
8 However, when the apparatus reaches the opening 104
9 in casing 100, the arm 232 springs radially outward
10 and engages a lower surface of the opening 104, thus
11 correctly locating the conduit 106 and the apparatus
12 150.

13

14 The ball 306 is then dropped down the bore of the
15 drill string or the coiled tubing string so that it
16 passes through the bore 164 of the apparatus 150 and
17 engages the ball seat 304, as shown in Fig. 7i.
18 Pressure is then applied by pressuring up the bore
19 of the drill string or coiled tubing string and the
20 bore 164 against the ball 306. The pressure is
21 typically in the order of 500 psi or more and is
22 generally increased up to around 1400 psi or more to
23 fully inflate the packers 156, 256.

24

25 As the pressure is increased over around 500 psi,
26 fluid from the bore 164 enters the annular chambers
27 176, 276 of the packers 156, 256 through the ports
28 166, 266. The increase in pressure in chambers 176,
29 276 serves to push the metal plates 162, 262
30 outwardly against the elastomeric coverings 168, 268
31 that are also pushed outwardly. The outward
32 movement of the elastomeric coverings 168, 268

1 continues until they engage the inner surface 106i
2 of the conduit 106 at or near the ends 106a, 106b.
3 Continued application of pressure into the annular
4 chambers 176, 276 causes the elastomeric coverings
5 168, 268 to radially expand the ends 106a, 106b as
6 shown in Fig. 6a, so that the ends 106a, 106b
7 contact the inner surface of the casing 100. It
8 will be appreciated that the conduit 106 shown in
9 Figs 7a to 7i is not provided with a friction and/or
10 sealing material 96, 110, although this can be
11 provided.

12

13 The radial expansion of the ends 106a, 106b secures
14 the conduit 106 in place around the opening 104 and
15 the contact between the conduit 106 and the casing
16 100 provides a seal (optionally with a friction
17 and/or sealing material 96, 110) that prevents the
18 ingress of sand, silt, shale or the like into the
19 main bore 100b of the casing 100. The flange for
20 the hook hanger can then be landed on the aperture
21 108 in the conduit 106. This is advantageous as the
22 size and shape of the aperture 108 will generally be
23 constant and the flange of the hook hanger can be
24 made to fit the aperture 108 easily. Also, as the
25 ends 106a, 106b only of the conduit 106 are radially
26 expanded, the radial expansion of these ends 106a,
27 106b should not interfere with the size and shape of
28 the aperture 108.

29

30 As the packers 156, 256 inflate, the centraliser 170
31 (Fig. 7a) disengages from the O-ring 172 located in
32 the groove 174. This is because an end 170a of the

1 centraliser 170 is contacted first by the expansion
2 of the elastomeric covering 168, 268, that serves to
3 pivot or tilt the centraliser 170 around the end
4 170a. This pivoting or tilting pushes the opposite
5 end 170b towards the elastomeric covering 168, 268
6 causing the O-ring 172 to be disengaged from the
7 groove 174. Further expansion of the packers 156,
8 256 causes the centraliser 170 to be pushed towards
9 the left in Fig. 7a so that it does not interfere
10 with the radial expansion of the end 106a, although
11 it will remain engaged with the apparatus 150 and
12 can be retrieved from the casing 100 therewith.

13

14 Where centraliser 180 is used (Fig. 9), the
15 relatively hard (and thus incompressible) rubber
16 transfers the expansion force of the packer 156 as
17 it expands to the end 106a of the conduit 106. This
18 causes the end 106a to be radially expanded whilst
19 the centraliser 180 remains in place on the
20 apparatus 150 and can be withdrawn from the casing
21 100 therewith.

22

23 It will be appreciated that as the elastomeric
24 coverings 168, 268 expand, they become shorter in
25 the axial direction. Thus, the shear screws 194,
26 294 that retain the second and third centralisers
27 190, 290 in place shear off, and the second and
28 third centralisers 190, 290 can move towards the
29 left in Figs 7b and 7i as the coverings 168, 268
30 contract. It will be appreciated that as the
31 apparatus 150 has been correctly located and the
32 expansion process has begun, there is no requirement

1 to keep the conduit 106 centralised with respect to
2 the longitudinal axis x of the apparatus 150. The
3 shear screws 194, 294 are typically rated to shear
4 at around 500 psi.

5
6 It will also be appreciated that the conduit 106
7 does not need to be retained in contact with the
8 apparatus 150 during the expansion process. Thus,
9 and with reference to Fig. 7c, as the pressure
10 reaches around 500 psi, the shear screws 209 shear
11 and fluid enters an annular chamber 211 at the left
12 hand side of the piston 202 through a port 213 that
13 transfers pressure from the bore 164. The piston
14 202 is pushed to the right in Fig. 7c and the fluid
15 pressure in chamber 208 is vented to outside the
16 apparatus 150 through the port 206. As the piston
17 202 moves to the right, the outer surface 202s no
18 longer engages the radial pistons 210 and they can
19 move radially inward so that they no longer engage
20 the conduit 106.

21
22 The pressure in bore 164 is increased causing the
23 packers 156, 256 to expand the ends 106a, 106b until
24 the pressure reaches around 3000 psi. At this
25 pressure, the shear screws 308 that retain the ball
26 seat 304 in the location shown in Fig. 7i shear, and
27 the ball seat 304 is forced to the right to the
28 position shown in phantom in Fig. 7i. The ball seat
29 304 engages the shoulder 310 so that it is retained
30 within apparatus 150 for retraction from the casing
31 100 therewith. With the ball seat 304 having moved
32 to engage the shoulder 310, this opens the ports 312

1 and allows pressure from within the bore 164 to be
2 vented to outwith the apparatus 150. The venting of
3 the pressure in the bore 164 allows the packers 156,
4 256 to deflate as the pressure in the annular
5 chambers 176, 276 is vented into the bore 164
6 through ports 166, 266 and out of the apparatus 150
7 through the ports 312.

8
9 It will be appreciated that the inflation of the
10 packer 256 can cause a seal in the annulus between
11 the apparatus 150 and the casing 100 at or near the
12 ball catcher 300, and it is sometimes the case that
13 the ball seat 304 cannot be forced to the right as
14 shown in Fig. 7i to release the pressure in the bore
15 164 because there exists a pressure lock or the like
16 between the packer 256 and some point below ball
17 catcher 300. In this case, the ball seat 304 will
18 not move to the right as the pressure in the annulus
19 around the ball catcher 300 is greater than the
20 pressure within the bore 164.

21
22 However, the apparatus 150 is provided with pressure
23 release channels 350, 352 that are located near the
24 packers 156, 256 respectively (see Figs 7a, 7b, 7c,
25 7g, 7h and 7i). The release channels 350, 352
26 provide a path through the apparatus 150 that allows
27 the pressure trapped at or near the ball catcher 300
28 to be vented to the left of the apparatus in Fig.
29 7a. The pressure at or near the ball catcher 300
30 enters the release channel 352 through a port 354
31 (Fig. 7i). The pressure then travels through the
32 release channel 352 and by-passes the packer 256 to

1 be vented to the annulus between the two
2 intermediate subs 220, 240, the locating sub 230 and
3 the conduit 106 through a port 356. The pressure
4 then enters release channel 350 through a further
5 port 358 (Fig. 7b) and travels through release
6 channel 350 to be vented to the left of the
7 apparatus 50 in Fig. 7a via a further port 360.
8 This equalises the pressure around the apparatus 350
9 and allows the pressure within the bore 164 to be
10 vented as the ball seat 304 can now move to engage
11 shoulder 310, thus allowing the pressure to bleed
12 off through ports 312 and also through the release
13 channels 350, 352 if required. Thus, the packers
14 156, 256 can then deflate as described above.

15

16 In the event that the ball seat 304 cannot be moved
17 under pressure to engage the shoulder 310 and thus
18 vent the pressure in the bore 164, the pressure can
19 be increased to around 4000 psi. At this pressure,
20 the burst discs 198, 298 rupture and pressure can be
21 vented from the bore 164 through the ports 166, 266
22 to the chambers 176, 276 where it is retained by an
23 O-ring seal 177, 277 and thus vented to outwith the
24 apparatus 150 through the ports 196, 296.

25

26 Thus, the present invention provides a method and
27 apparatus for performing remedial and installation
28 operations that in certain embodiments uses at least
29 one inflatable element to expand portion of a
30 lightweight and/or heavyweight expandable member.
31 The present invention in certain embodiments also
32 provides a method and apparatus for creating a

1 conduit between an opening drilled into a casing to
2 form a lateral borehole and a flange on a hook
3 hanger.

4

5 Modifications and improvements may be made to the
6 foregoing without departing from the scope of the
7 present invention.

8

1 **Claims**

2

3 1. A tubular remedial apparatus for performing
4 downhole remedial or repair operations on
5 downhole tubulars such as casing, liner or the
6 like in a wellbore, the apparatus comprising an
7 expandable tubular member and at least one
8 expander element.

9

10 2. Apparatus according to claim 1, wherein the
11 expandable member comprises a tubular with a
12 heavyweight portion and two lightweight
13 portions.

14

15 3. Apparatus according to claim 1 or claim 2,
16 wherein the expandable member is provided with
17 at least one orifice.

18

19 4. Apparatus according to any preceding claim,
20 comprising, two axially spaced-apart expander
21 elements.

22

23 5. Apparatus according to any preceding claim,
24 wherein the or each expander element comprises
25 an inflatable device.

26

27 6. A method of performing downhole repair or
28 remedial operations, the method comprising the
29 steps of providing an expandable member;
30 locating the member in a tubular in the
31 borehole; providing at least one expander
32 element and locating this within the expandable

- 1 member; and actuating the or each expander
2 element to radially expand at least a portion
3 of the expandable member against the tubular.
4
- 5 7. A method according to claim 6, wherein the
6 expandable member is located over a valve,
7 perforation, or orifice located in the tubular.
8
- 9 8. A method according to claim 7, wherein the
10 expandable member is expanded at spaced-apart
11 locations that straddle the valve, perforation
12 or orifice.
13
- 14 9. A method according to claim 7, wherein the
15 expandable member is expanded along its entire
16 length by actuating the expander element to
17 expand a first portion of the expandable
18 member, de-actuating it and moving it to
19 another location in the expandable member, and
20 then re-actuating it to expand the expandable
21 member at the other location.
22
- 23 10. A lateral tubular adapter apparatus, the
24 apparatus having a longitudinal bore and at
25 least one expander element.
26
- 27 11. Apparatus according to claim 10, having first
28 and second axially spaced-apart expander
29 elements.
30

1 12. Apparatus according to claim 10 or claim 11,
2 wherein the or each expander element comprises
3 an inflatable element.

4
5 13. Apparatus according to any one of claims 10 to
6 12, having an annular chamber in fluid
7 communication with the bore of the device.

8
9 14. Apparatus according to claim 13, wherein the or
10 each inflatable element includes one or more
11 ports in fluid communication with the annular
12 chamber.

13
14 15. Apparatus according to claim 14, wherein the or
15 each port includes a rupture or burst disc
16 therein.

17
18 16. Apparatus according to any one of claims 10 to
19 15, having an elastomeric covering over at
20 least a portion thereof.

21
22 17. Apparatus according to any one of claims 10 to
23 16, having a centraliser located at or near the
24 or each inflatable element to control inflation
25 of the or each inflatable element.

26
27 18. Apparatus according to any one of claims 10 to
28 17, wherein at least a portion of the conduit
29 is swaged.

30
31 19. Apparatus according to any one of claims 10 to
32 18, including a retainer sub mounted on the

1 conduit and having an array of radial pistons
2 being circumferentially spaced-apart from one
3 another.
4

5 20. A method of hanging a lateral tubular from a
6 cased wellbore, the method comprising the steps
7 of providing a conduit having a longitudinal
8 bore and at least one expander element, the
9 conduit having an aperture therein; locating
10 the conduit at or near a lateral opening in the
11 casing of the borehole; and expanding the or
12 each expander element to radially expand
13 portions of the conduit on opposite sides of
14 the aperture.
15

16 21. A method according to claim 20, wherein the
17 aperture in the conduit is teardrop-shaped.
18

19 22. A method according to claim 20 or 21, including
20 the step of locating a locating arm in an
21 elongated portion of the aperture in the
22 conduit, and running the apparatus into the
23 borehole until the locating arm locates the
24 opening to the lateral borehole.
25

1 / 17

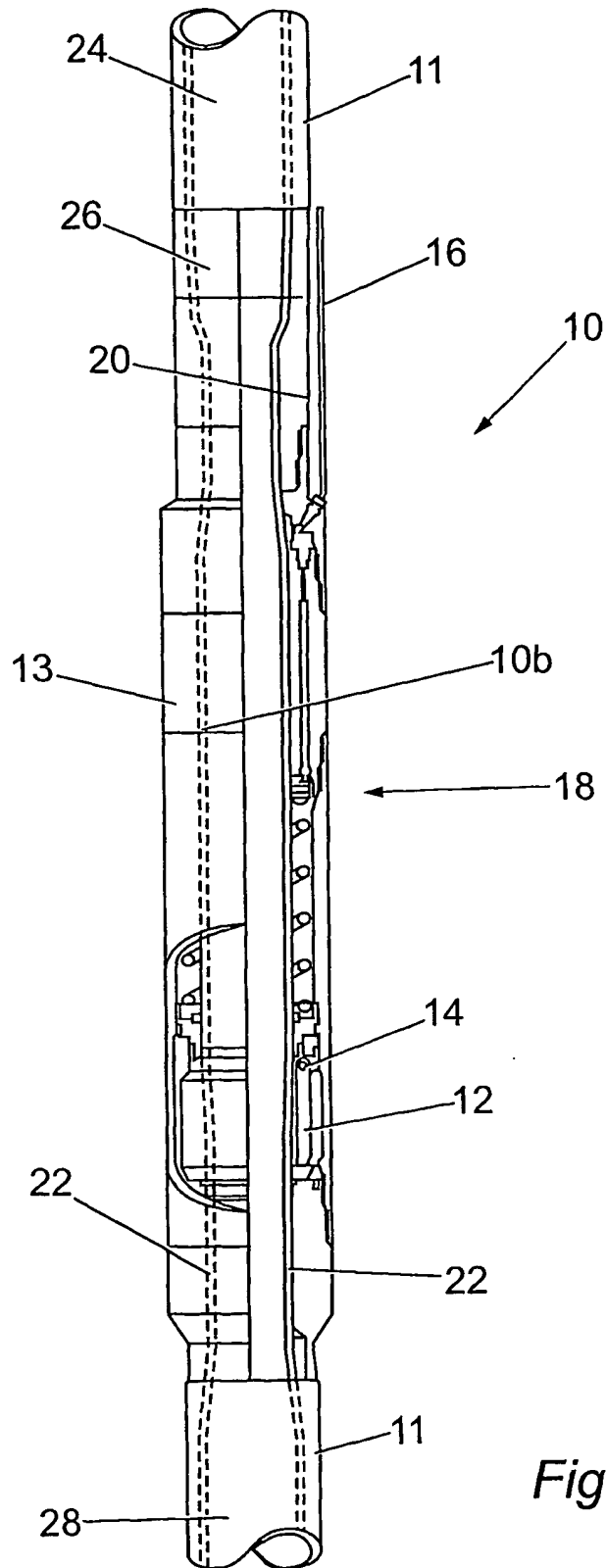
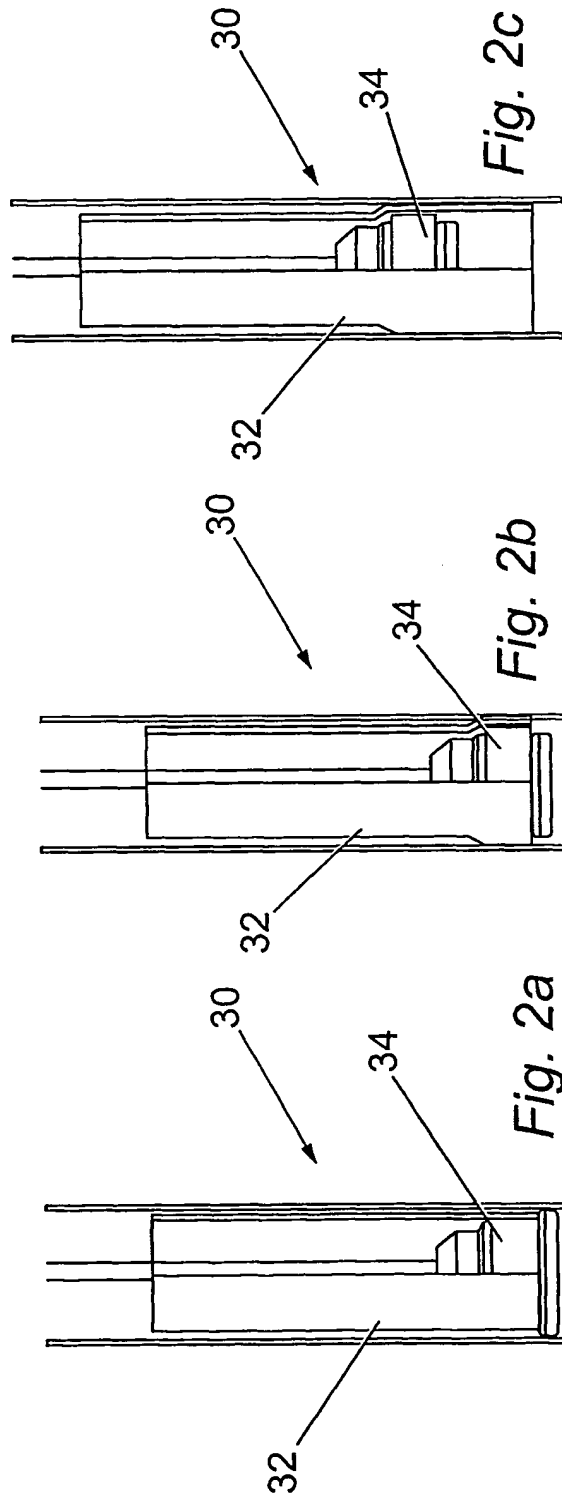


Fig. 1

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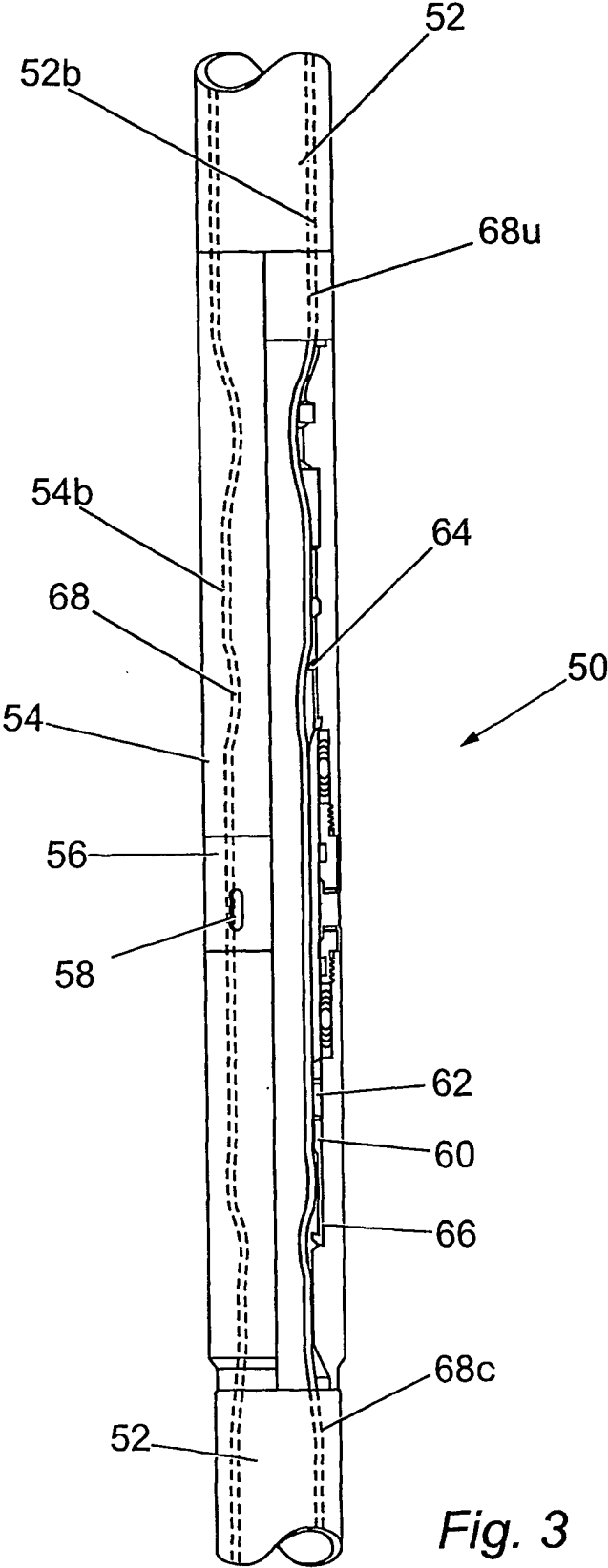
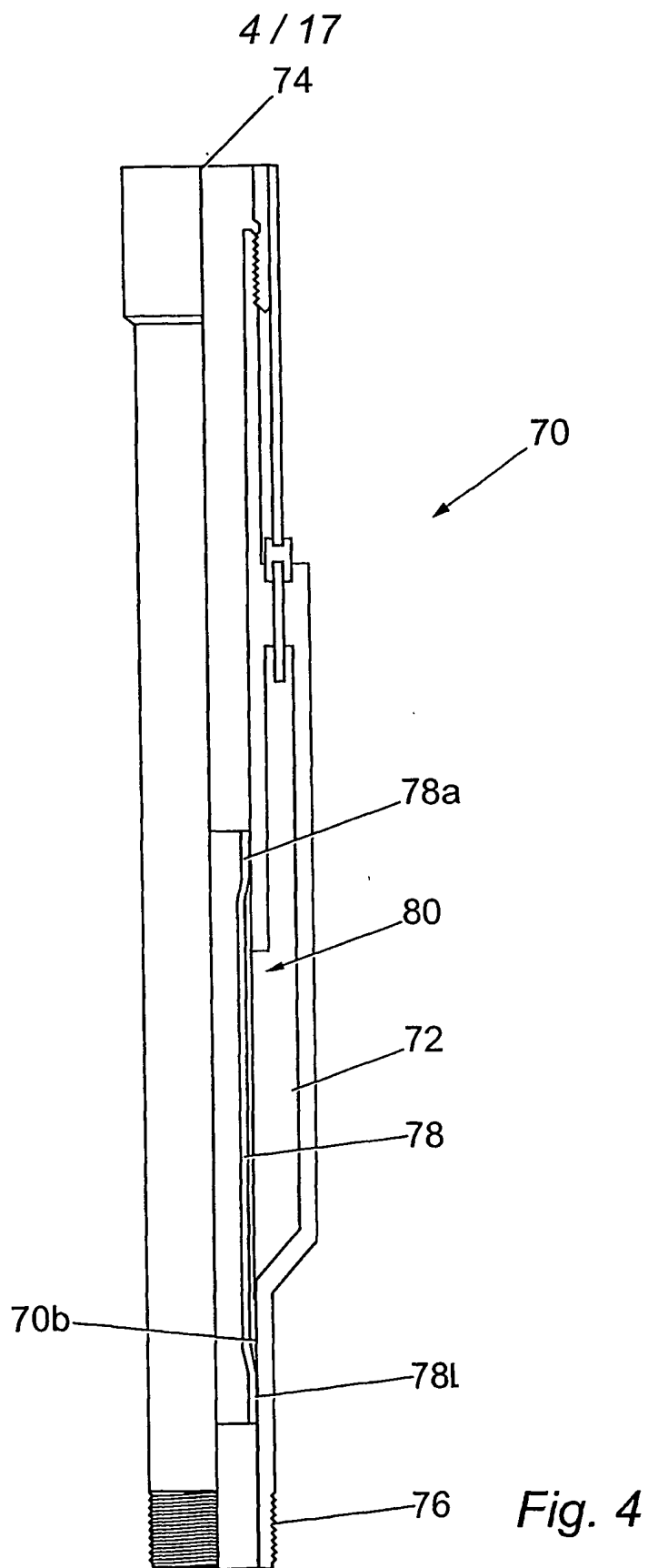
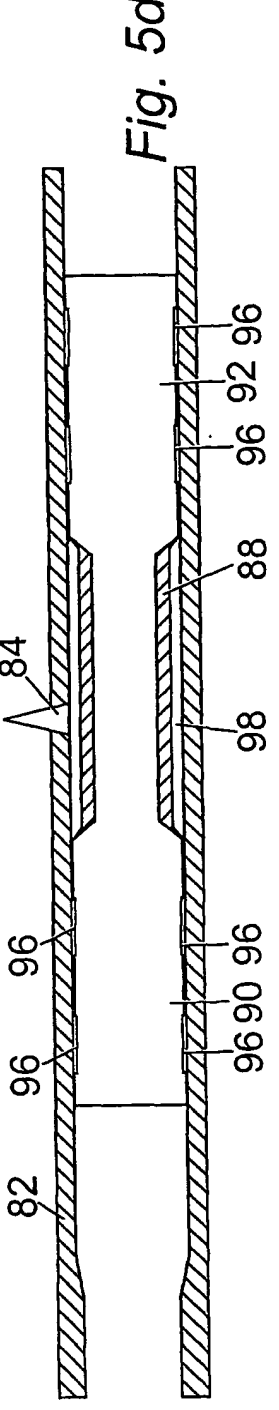
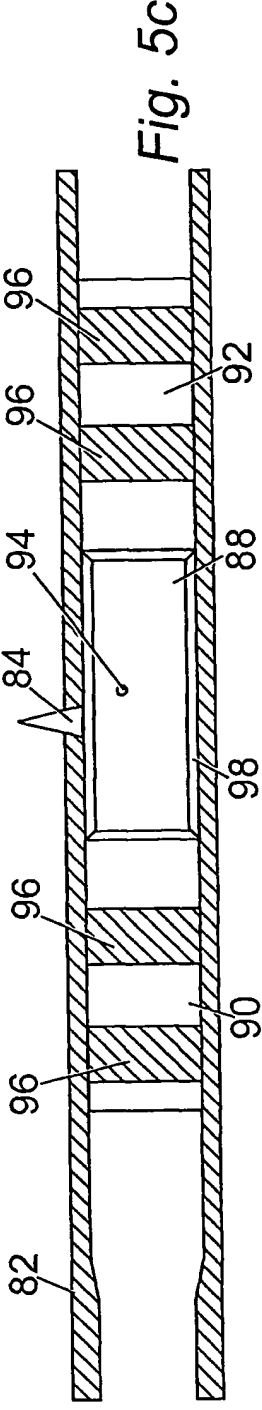
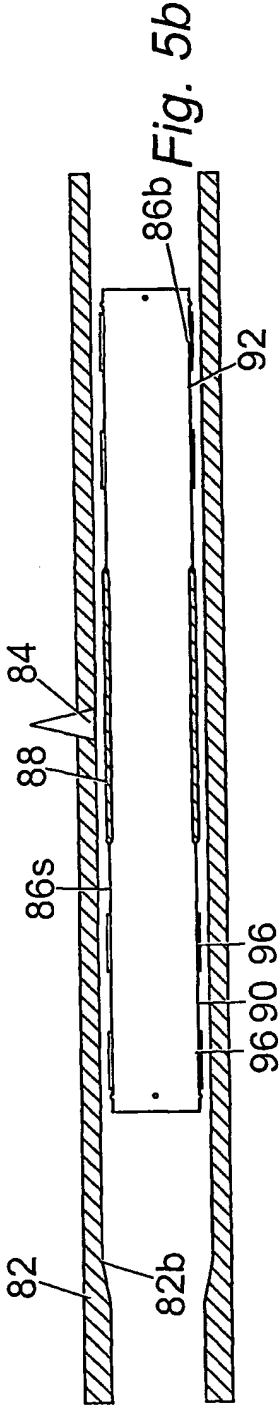
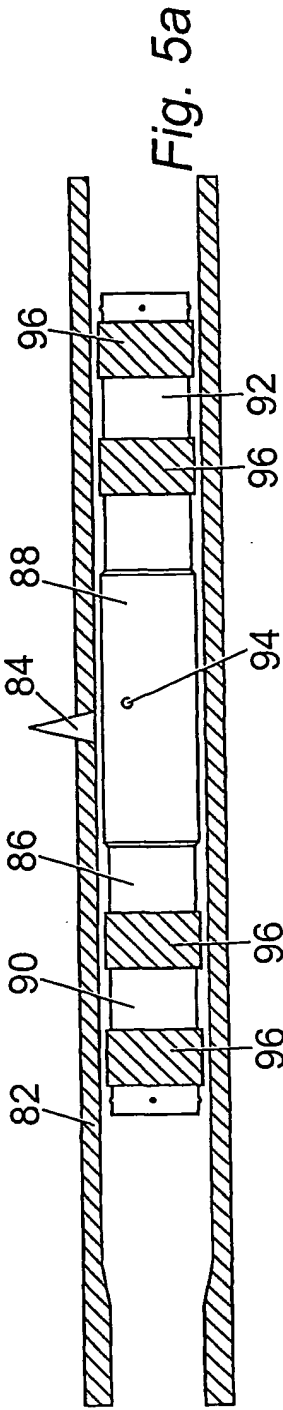
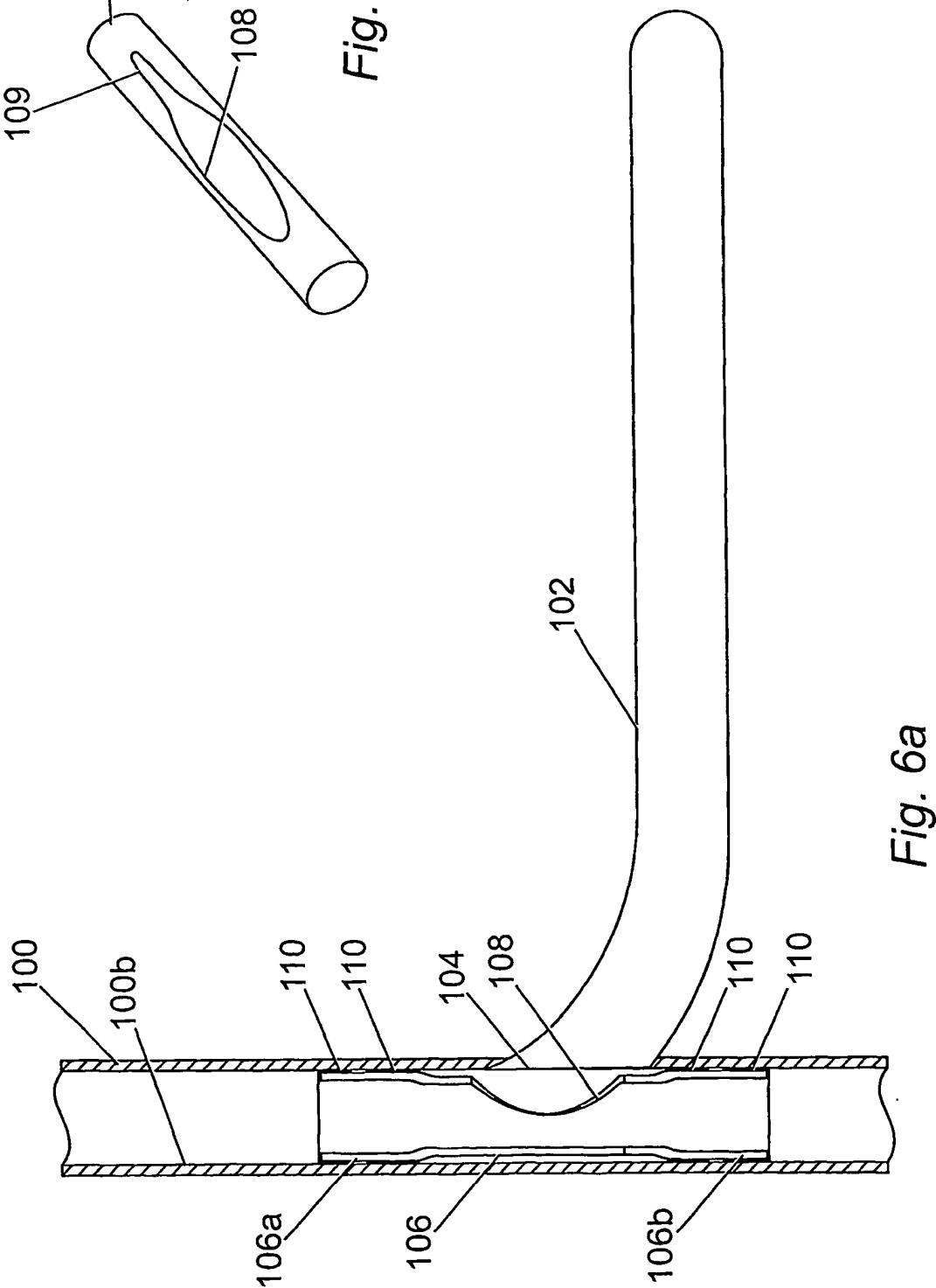
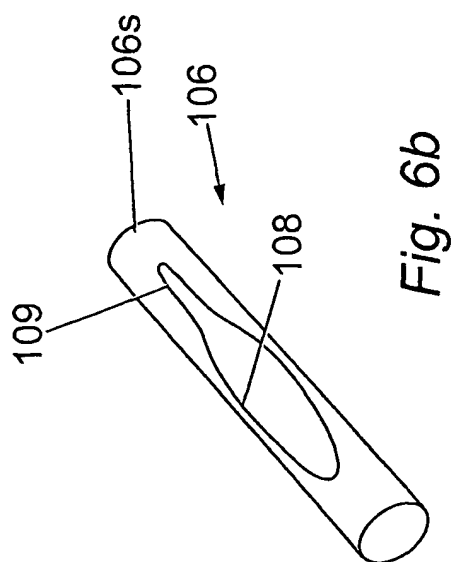


Fig. 3





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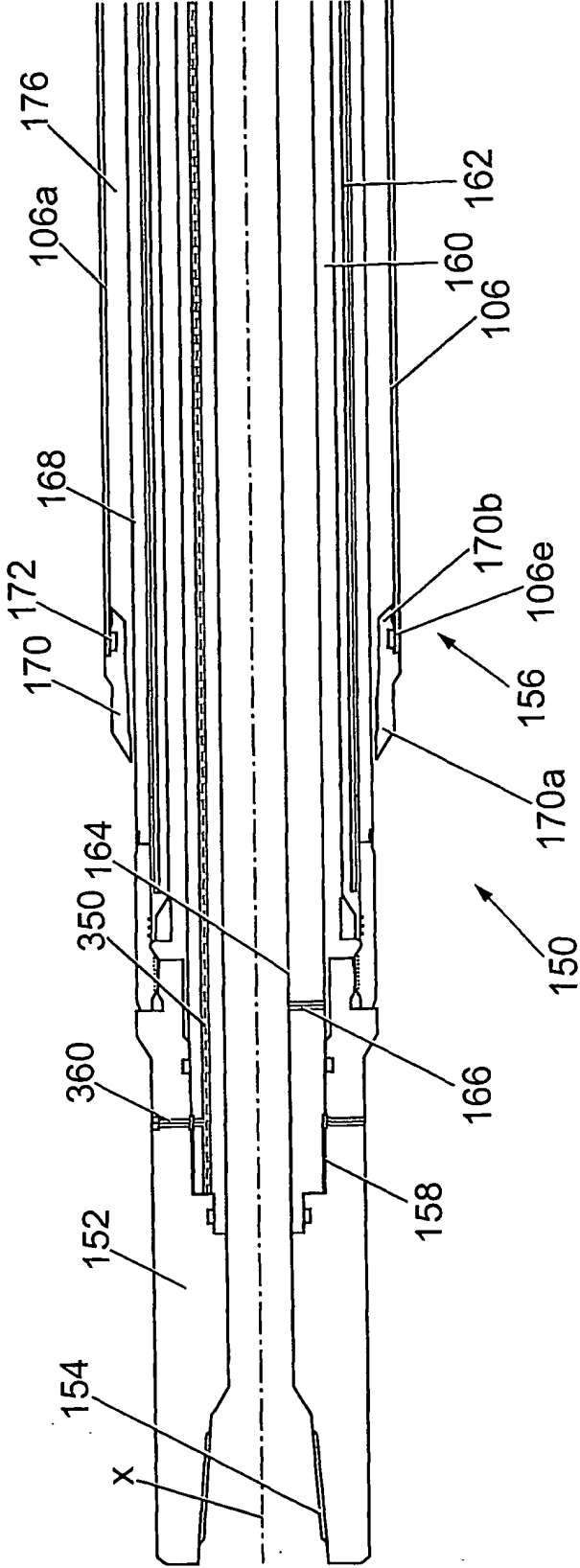
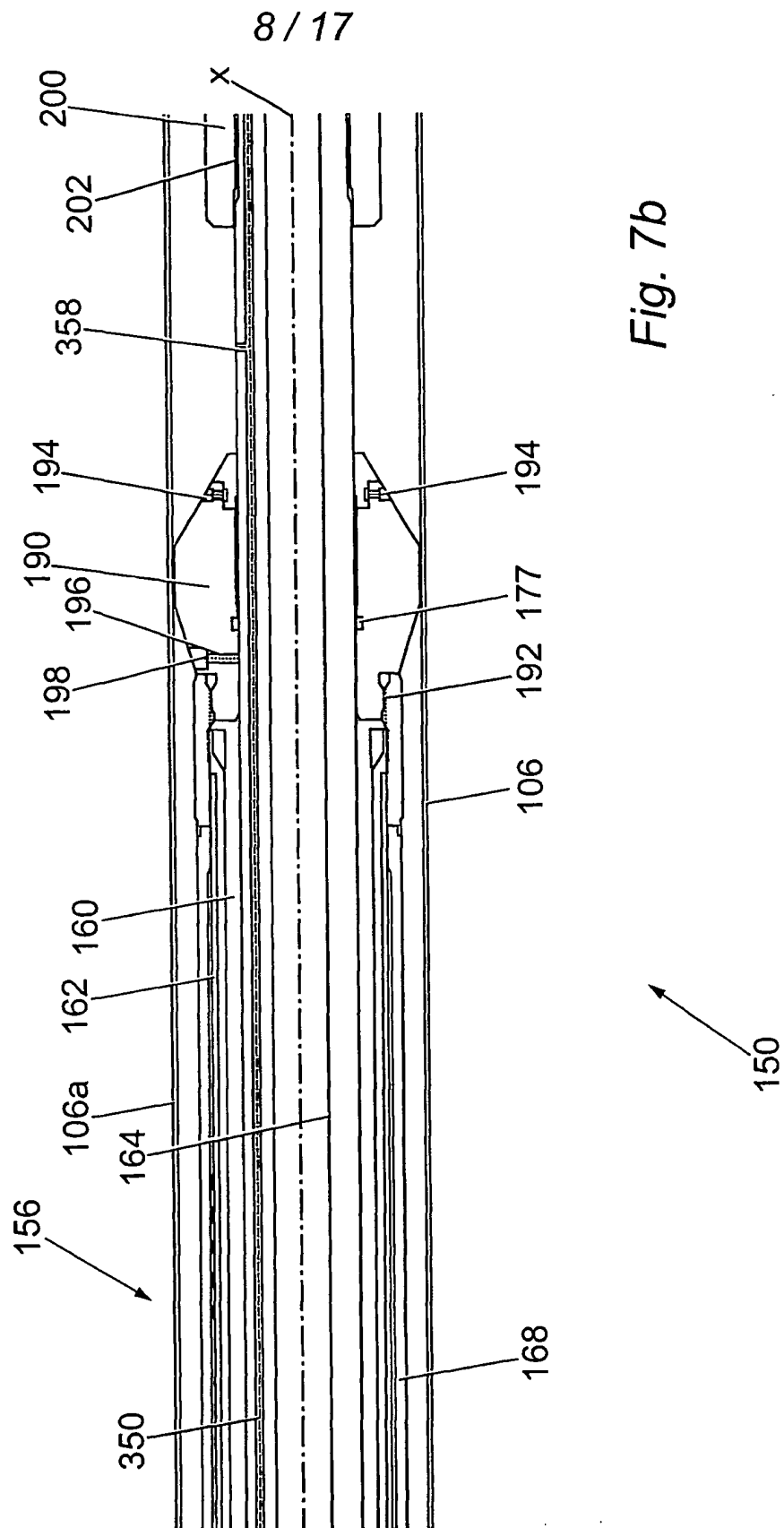


Fig. 7a



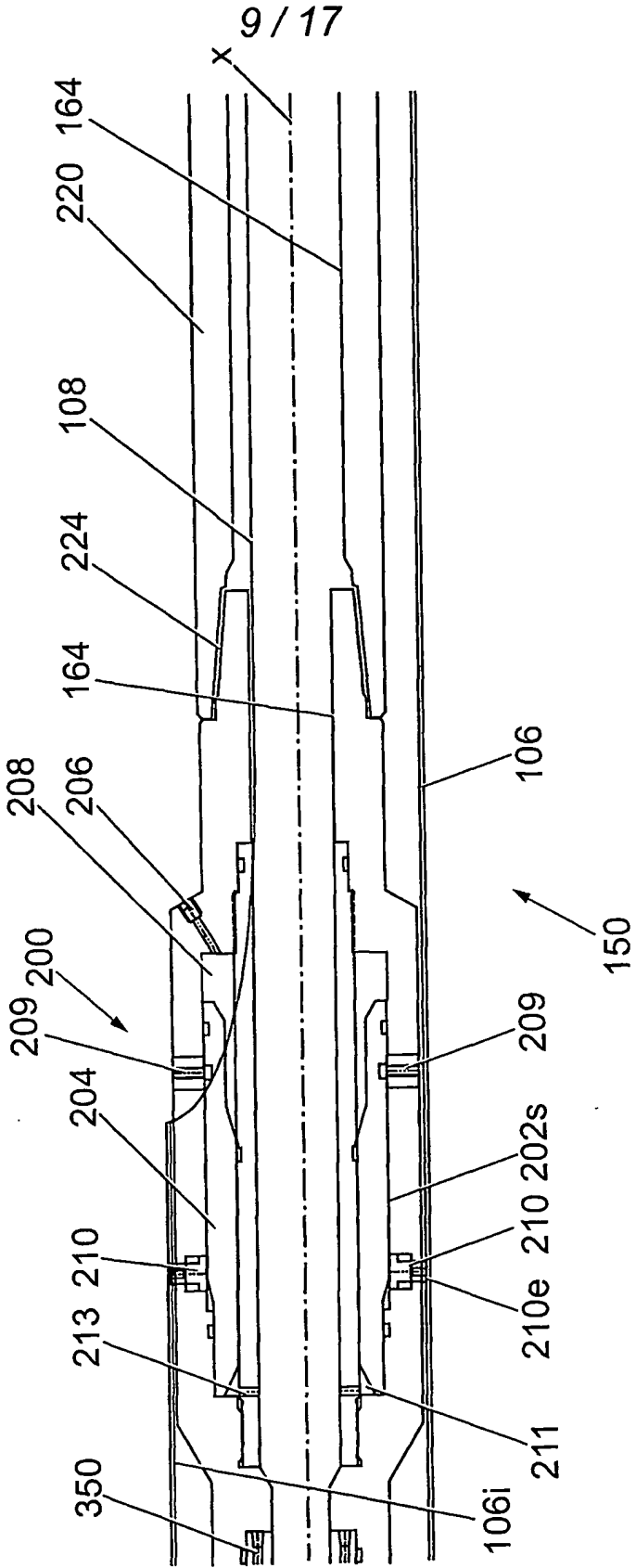
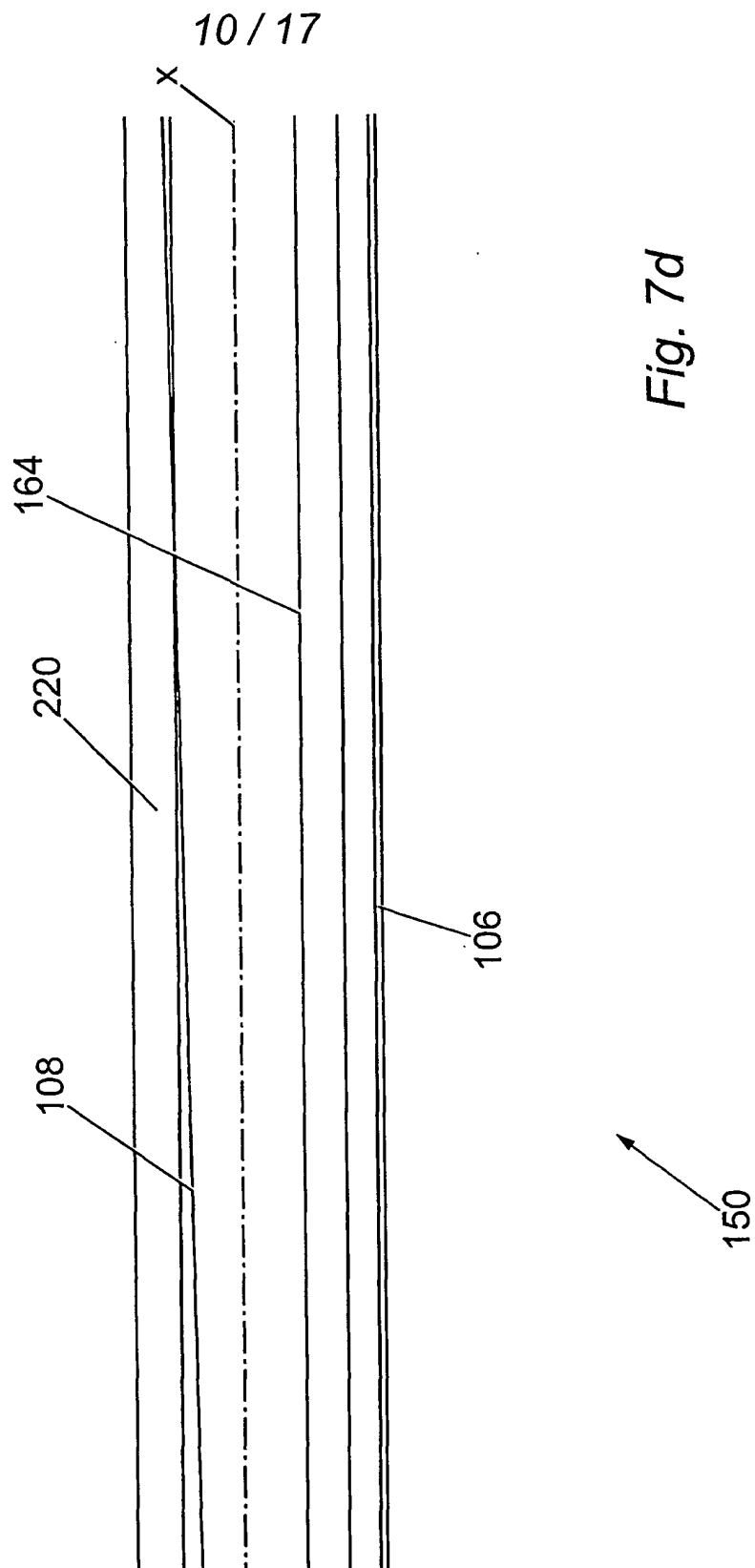
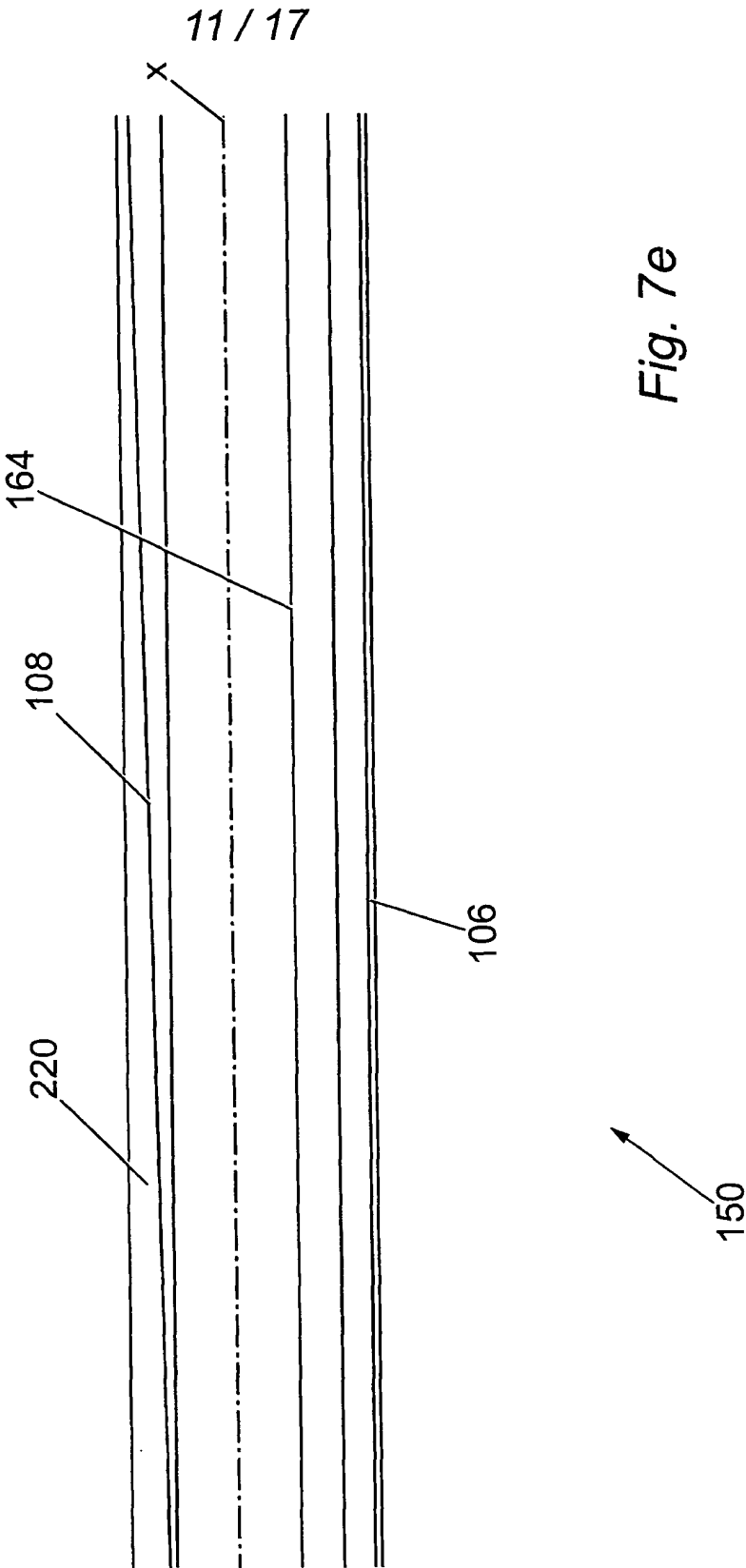
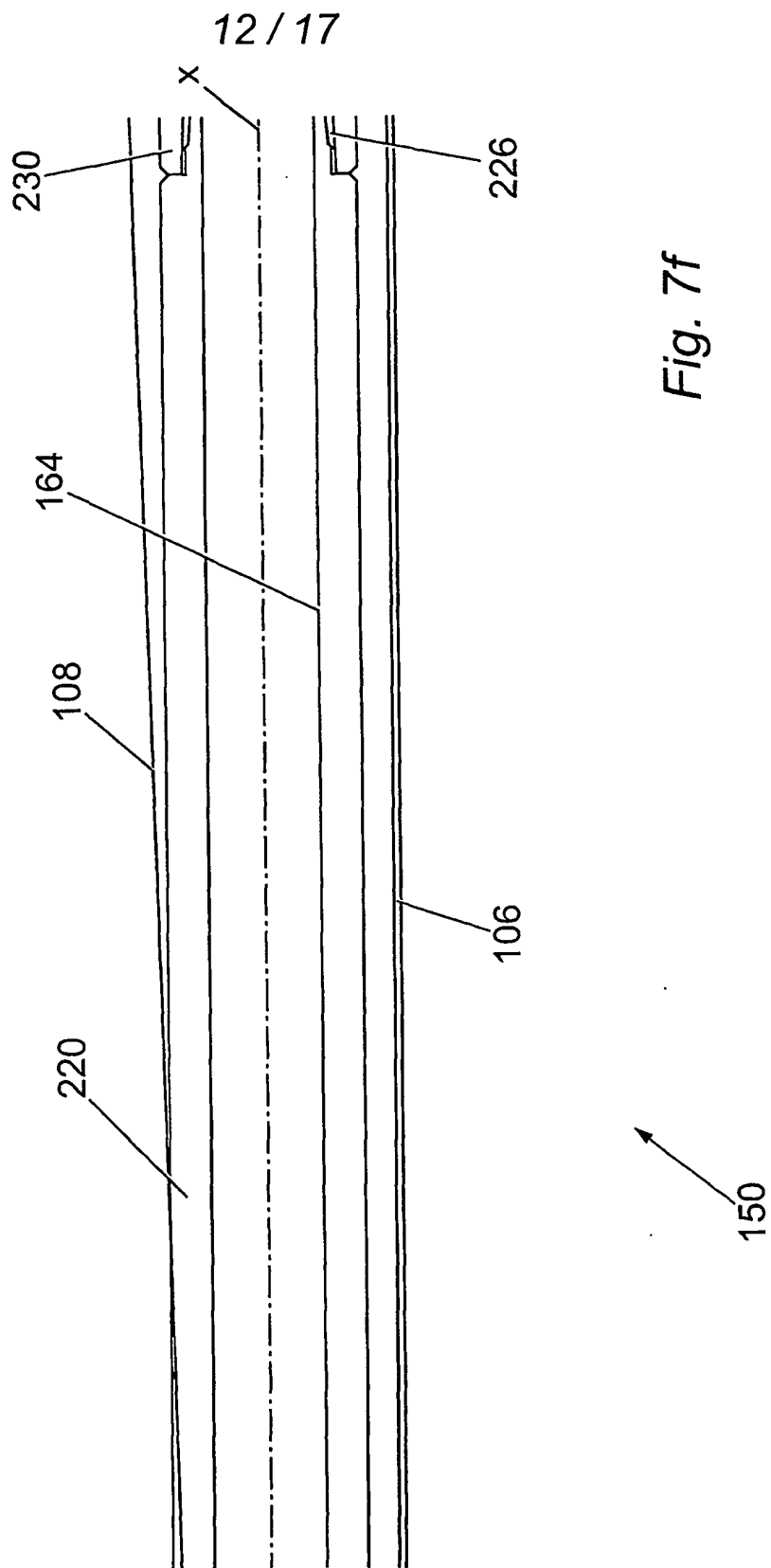
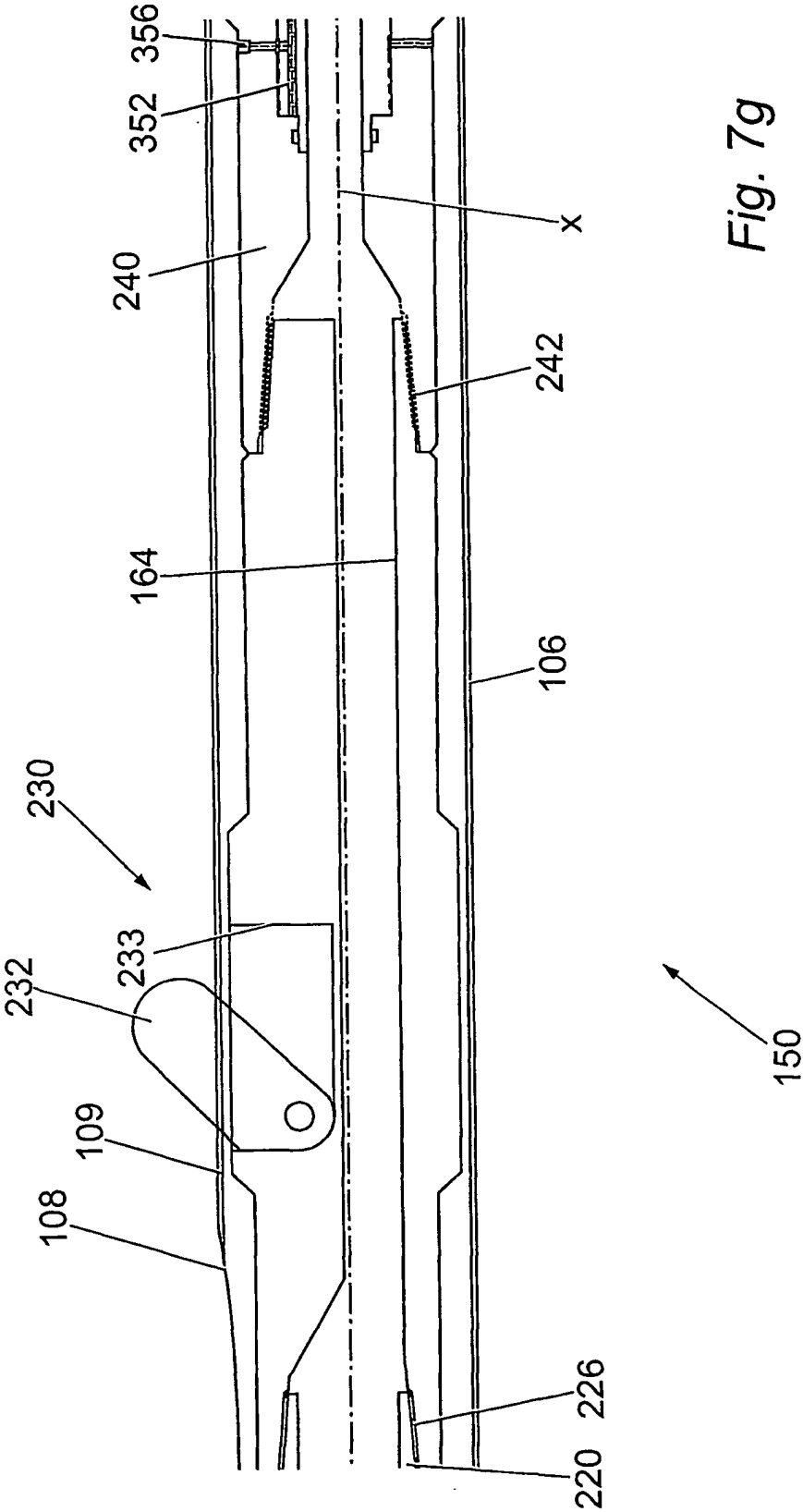


Fig. 7c









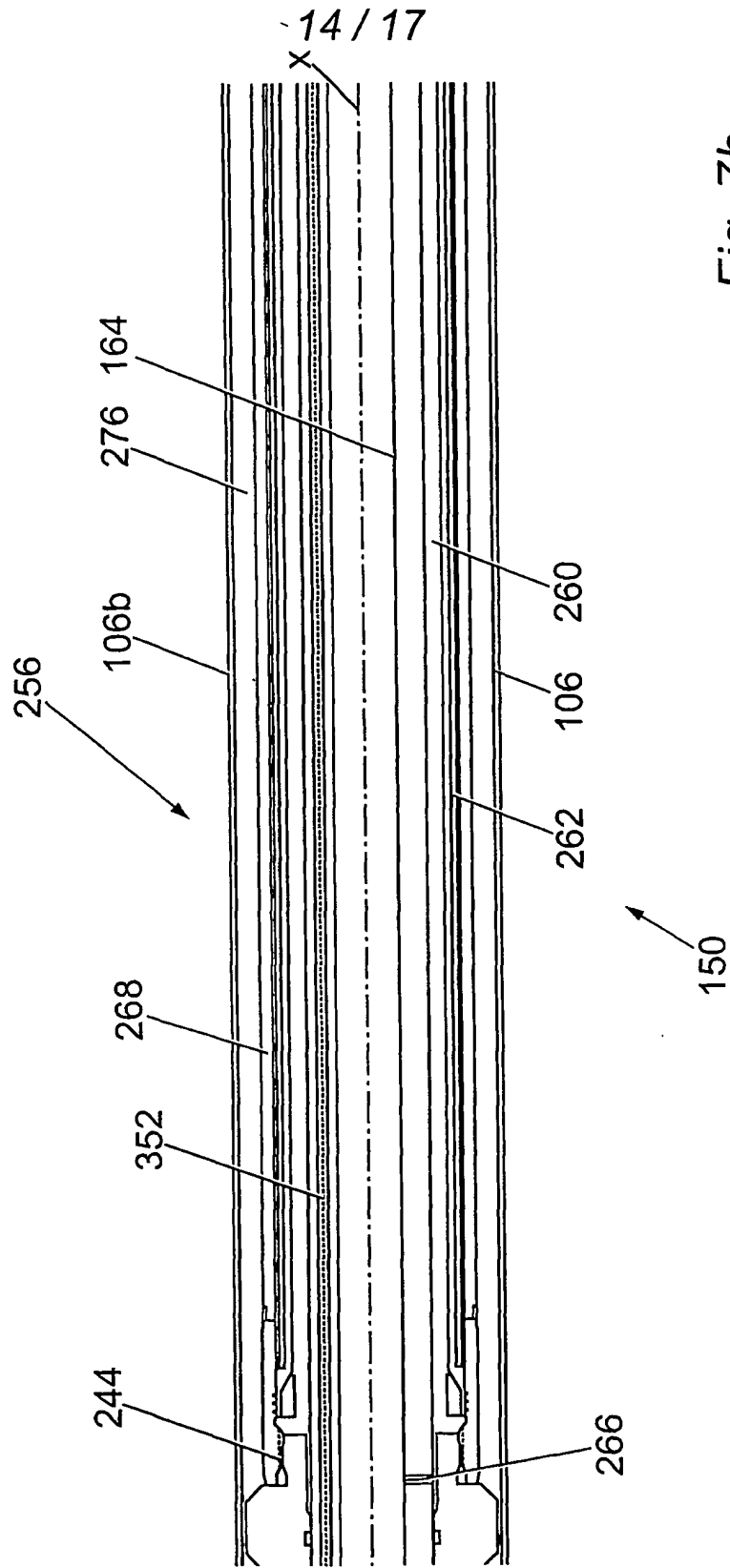
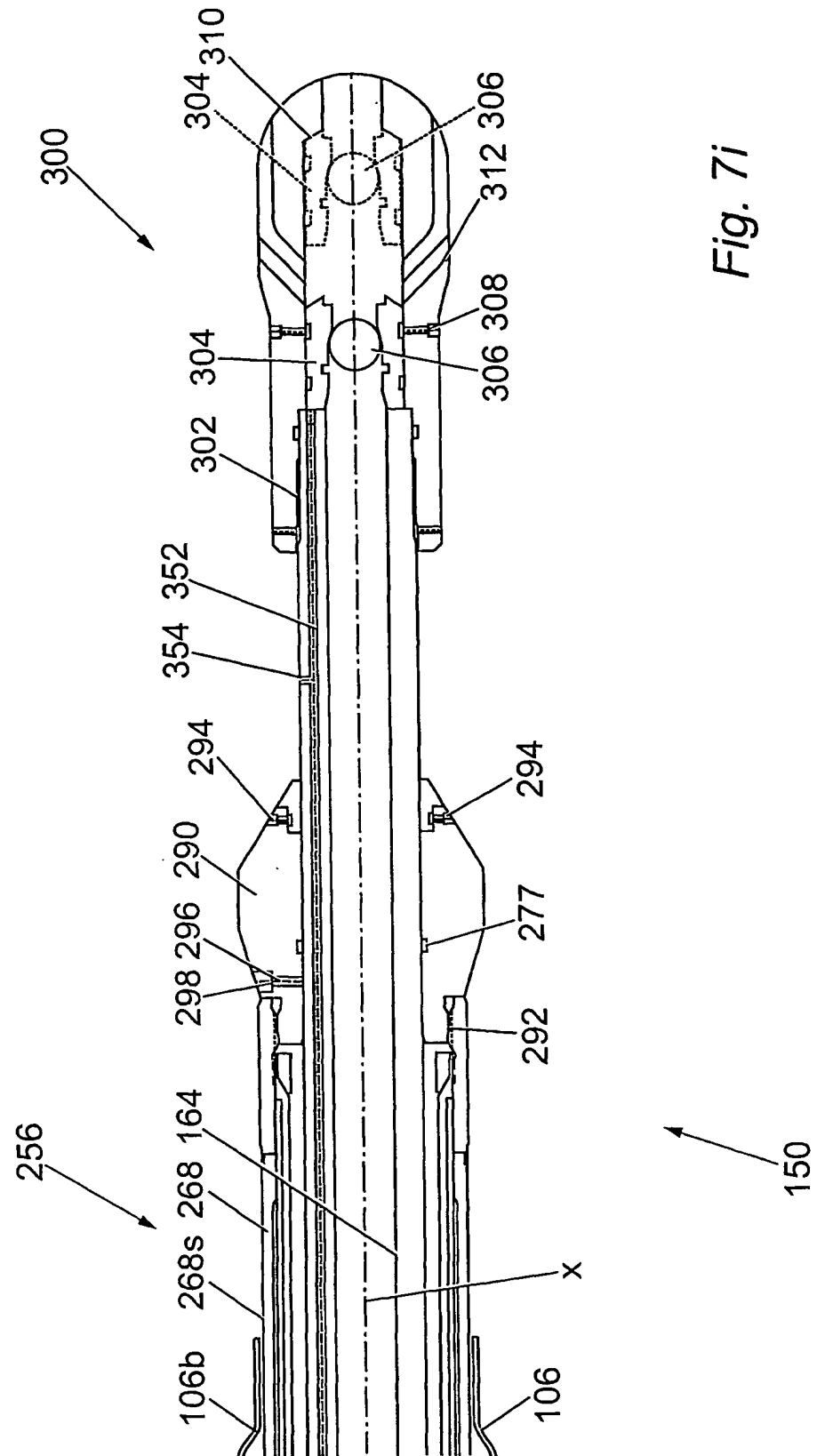


Fig. 7h

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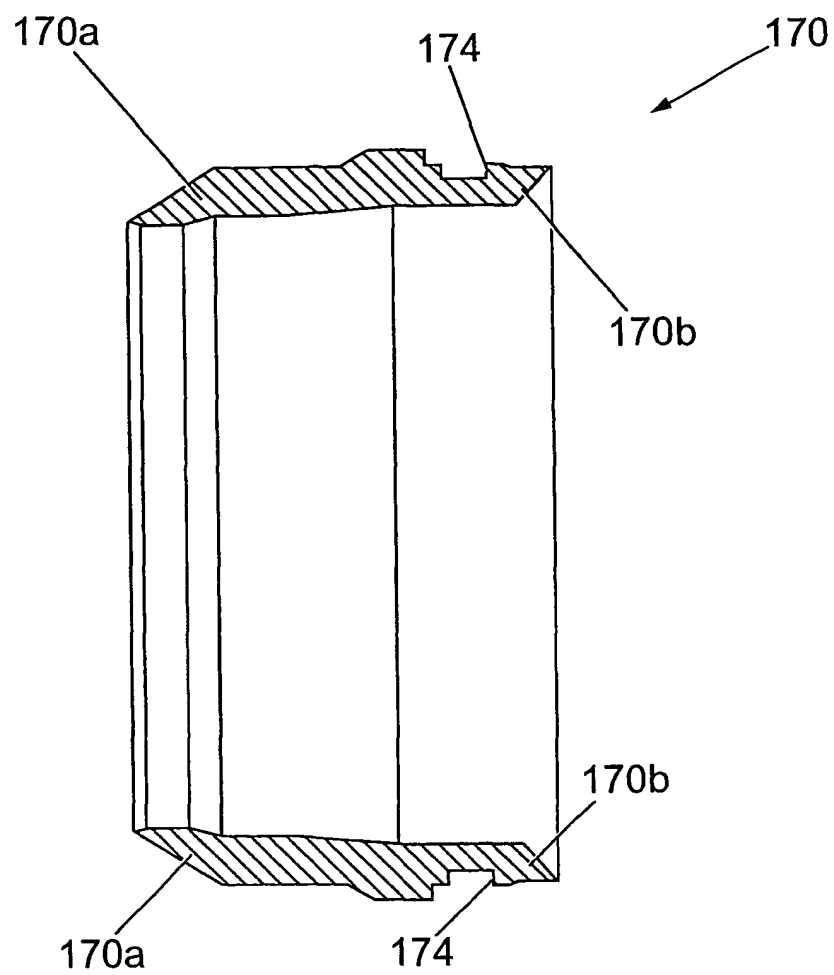


Fig. 8

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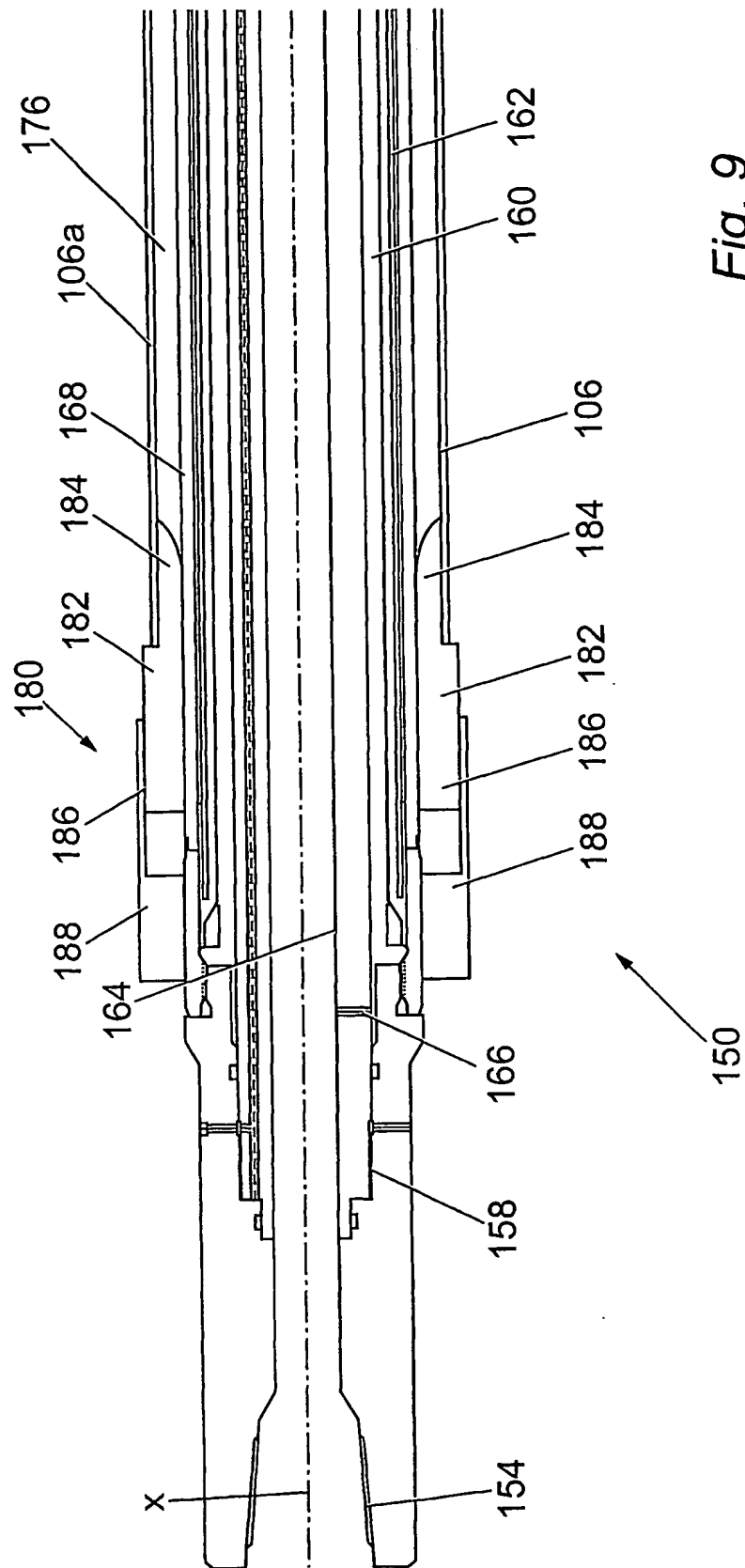


Fig. 9

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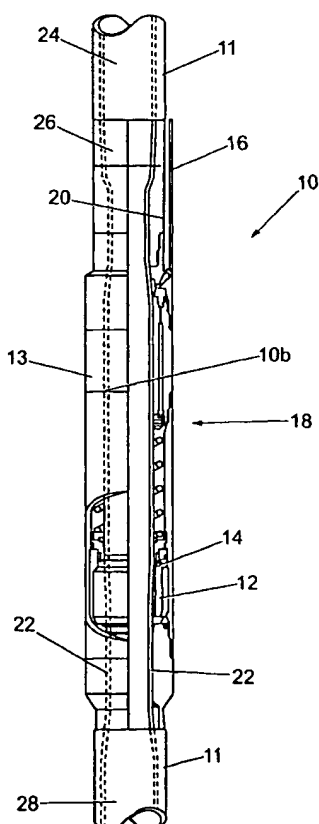
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[Continued on next page]

(54) Title: METHOD AND APPARATUS FOR REPAIR OPERATIONS DOWNHOLE



(57) Abstract: Aspects of the invention relate to apparatus and methods for remedial and repair operations downhole. Certain embodiments of apparatus include a lightweight expandable member (22) that can be radially expanded to increased its inner and outer diameters using an inflatable element (34). The lightweight member (22) can be used to repair a faulty safety valve flapper (12) for example. The invention also relates to lateral tubular adapter apparatus and a method of hanging a lateral from a cased borehole.

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A. CLASSIFICATION OF SUBJECT MATTER

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E21B34/06

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)

IPC 7 E21B

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practical, search terms used)

EPO-Internal, PAJ, WPI Data

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category *	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	WO 00 37768 A (WEATHERFORD LAMB) 29 June 2000 (2000-06-29)	1,4,6-9
Y	abstract; figures page 5, line 6-15 page 7, line 14-25 ---	3
X	US 3 477 506 A (MALONE BILLY C) 11 November 1969 (1969-11-11) abstract; figures column 4, line 32 -column 5, line 63 column 6, line 53-71 column 10, line 3 - line 38 ---	1,2,5-9
X	WO 93 25799 A (SHELL CANADA LTD ;SHELL INT RESEARCH (NL)) 23 December 1993 (1993-12-23) page 5, line 12-18; figures ---	1,5
	--- -/--	



Further documents are listed in the continuation of box C.



Patent family members are listed in annex.

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Date of the actual completion of the international search

23 August 2002

Date of mailing of the international search report

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INTERNATIONAL SEARCH REPORT

International Application No.

PCT/GB 01/05614

C.(Continuation) DOCUMENTS CONSIDERED TO BE RELEVANT		
Category *	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 3 712 376 A (YOUNG J ET AL) 23 January 1973 (1973-01-23) column 6, line 37 -column 7, line 13 column 9, line 27 -column 10, line 26 ---	1,4,6-8
A	WO 00 37773 A (PETROLINE WELLSYSTEMS LTD ;ASTEC DEV LTD (GB)) 29 June 2000 (2000-06-29) abstract; figures page 11, line 28 -page 12, line 12 ---	1
A	FR 2 791 732 A (SOC D COOPERATION MINIERE ET I) 6 October 2000 (2000-10-06) abstract; figures 2,3 ---	1
P,A	GB 2 357 099 A (BAKER HUGHES INC) 13 June 2001 (2001-06-13)	1
P,X	abstract; figures ---	20
Y	US 3 356 139 A (LAMB CHARLES P ET AL) 5 December 1967 (1967-12-05) abstract; figure 1 column 2, line 27 - line 63 ---	3
X	US 5 964 288 A (SALTEL JEAN-LOUIS ET AL) 12 October 1999 (1999-10-12)	10,12,20
Y	abstract; figures 11-16 column 4, line 47 -column 5, line 15 ---	11
Y	EP 0 961 007 A (HALLIBURTON ENERGY SERV INC) 1 December 1999 (1999-12-01) abstract; figure 8 paragraph '0159! - paragraph '0163! ---	11
X	US 6 070 671 A (CUMMING FRANCIS ALEXANDER ET AL) 6 June 2000 (2000-06-06) abstract; figures ---	10
E	WO 01 98623 A (COOK ROBERT LANCE ;HAUT RICHARD CARL (US); ZWALD EDWIN ARNOLD JR () 27 December 2001 (2001-12-27) page 19, line 16 - line 33; figure 1 page 22, line 3 - line 10 -----	1

INTERNATIONAL SEARCH REPORT

International Application No.
PCT/GB 01/05614

Box I Observations where certain claims were found unsearchable (Continuation of Item 1 of first sheet)

This International Search Report has not been established in respect of certain claims under Article 17(2)(a) for the following reasons:

1. ☐ Claims Nos.:
because they relate to subject matter not required to be searched by this Authority, namely:
2. ☐ Claims Nos.:
because they relate to parts of the International Application that do not comply with the prescribed requirements to such an extent that no meaningful International Search can be carried out, specifically:
3. ☐ Claims Nos.:
because they are dependent claims and are not drafted in accordance with the second and third sentences of Rule 6.4(a).

Box II Observations where unity of invention is lacking (Continuation of Item 2 of first sheet)

This International Searching Authority found multiple inventions in this international application, as follows:

see additional sheet

1. ☒ As all required additional search fees were timely paid by the applicant, this International Search Report covers all searchable claims.
2. ☐ As all searchable claims could be searched without effort justifying an additional fee, this Authority did not invite payment of any additional fee.
3. ☐ As only some of the required additional search fees were timely paid by the applicant, this International Search Report covers only those claims for which fees were paid, specifically claims Nos.:
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- ☐ The additional search fees were accompanied by the applicant's protest.
- ☒ No protest accompanied the payment of additional search fees.

FURTHER INFORMATION CONTINUED FROM PCT/ISA/ 210

This International Searching Authority found multiple (groups of) inventions in this international application, as follows:

1. Claims: 1,2,4-9

Remedial operations including a tubular with heavyweight and lightweight portions

2. Claims: 1,3

Expandable member with an orifice

3. Claims: 10-22

A lateral adapter apparatus

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